VALUATION OF OIL AND GAS LANDS

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VALUATION OF OIL AND GAS LANDS

BY

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PREFACE

The importance of valuation is realized only when one considers the number of decisions affected by values. Think of the losses incurred from buying worthless oil land or stock, or by extravagant expenditures for improvements! A knowledge of the limited amount of recoverable reserves would instill many an executive with a sober sense of his responsibility in operating oil or gas properties in the most economical manner. It would decrease the number of unnecessary wells and secure greater cooperation between operators. There is no operating or development procedure which increases income or decreases cost which does not affect the productive value of oil and gas lands.

The purpose of this book is to present in as simple a manner as is consistent with the technical nature of the subject, the principles underlying the valuation of oil and gas lands. The subject is intimately connected with geology, engineering, economics, accounting, and taxation, but I have endeavored to refrain from expanding on any of these subjects when it did not relate to the main theme of the book.

Recently much attention has been devoted to the valuation of oil and gas lands for taxation purposes, but the need of proper valuation is even greater when buying, selling or operating oil and gas properties. The emphasis of this book is placed upon principles underlying sound valuations and are of general application. However, one chapter is devoted to taxation purposes.

Many persons, including accountants, lawyers, engineers, geologists, and operators are interested in the valuation of oil and gas lands. I have endeavored to keep these various groups in mind when preparing the manuscript.

I am indebted to many persons for suggestions in the preparation of this book, especially my former colleagues in the Oil and Gas Valuation Section, Income Tax Unit, United States Treasury Department. This book was written at the suggestion Prof. Roswell H. Johnson, of the University of Pittsburgh.

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Mr. Ben K. Stroud, of the National Tube Company has made many valuable suggestions and criticisms. I have endeavored through footnote references to make suitable acknowledgement of the various sources of information.

ROBERT WESLEY BROWN.

SHREVEPORT, LOUISIANA,
February, 1924.

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VALUATION OF OIL AND GAS LANDS

CHAPTER I

THE NATURE AND DETERMINATION OF VALUE

Definition of Value

The term "value" is commonly used without much consideration being given to its exact meaning. Even economists and writers on the subject are not agreed concerning its definition. It is said that Sydney Smith joined the Political Economy Club to learn the meaning of this term and resigned from the club because the other members knew as little as he about it.

Two Meanings of Value.—The word "value," it is observed, has two different meanings, and sometimes expresses the utility of some particular object, and sometimes the power of purchasing other goods which the possession of that object conveys. The one may be called "Value in use," the other "Value in exchange." The things which have the greatest value in use have frequently little or no value in exchange, and, on the contrary, those which have the greatest value in exchange have frequently little or no value in use. Nothing is more useful than water, but it will purchase scarce anything; scarce anything can be had in exchange for it. A diamond, on the contrary has scarce any value in use, but a very great quantity of goods may frequently be had in exchange for it.[1]

Value in Exchange.—Value in exchange may be measured in terms of a barter, as one suit of clothes may be valued at five pairs of shoes, or it may be measured in terms of money, as one suit of clothes is valued at $60, in which case (when expressed in terms of money) value has the same meaning as price. By "exchange value" of an oil property is meant the price it will bring or its sales value. Modern economists now restrict the term "value" to this meaning.

[1] Smith, Adam: "Wealth of Nations," Bk. I, chap. IV, p. 34.

Value in Use.—Value in use has reference to the satisfaction to be derived from the use of a given commodity relative to the satisfaction to be derived from other commodities. In this sense, that commodity is most valuable which yields the greatest satisfaction. In the case of an oil property this satisfaction is derived from the income of the land, that land being most valuable which produces the greatest income in the least time, since we are not concerned with the efficiency, or manner in which the income is spent. This value of an oil property is synonymous with its productive value, which may be defined as the present value of its future net income; it is the capital which the future income can repay after due allowance has been made for interest and risk.

Measure of Productive Value.—The present value method has been devised to determine productive value. This method was used in the appraisals of the properties of the Independent Oil Producers' Agency and is most excellently described in their report. It is based on the following principles:[1]

1. That from each property there will ultimately be produced a certain total quantity of oil.
2. That in the production of that oil a certain total quantity of money will be expended.
3. That a certain total amount of money will be received from the oil.
4. That the total net receipts will be the total gross receipts less the cost of development and production.
5. That the present value of the net receipts must be such an amount that when invested by a purchaser it will be returned with 8 per cent interest additional during the life of the property.

In this report, interest is computed at 8 per cent. With the exception that different rates of interest have been used in other appraisals, the method as outlined has been quite generally applied.

Factors Affecting Productive Value.—The factors involved in the determination of productive value—estimation of recoverable reserves, selling price of oil, development and operating costs, and allowance for discount and risk are quite inter-related. For example, an increase in the price of oil or a decrease in the

[1] Appraisal of the Independent Oil Producers' Agency, 1915. Appraisal Committee: M. L. Requa, M. V. Quigg, R. S. Haseltine; Engineer, Thomas Cox.

operating expense will prolong the life of the well and so increase the amount of recoverable oil. Prolonging the life of the well increases the effect of the allowance for discount. Allowance may be made for risk either through the use of a high discount factor, or through conservative estimates of the several elements entering into value, as oil reserves, future costs, and future prices of oil.

Industrial and financial conditions affect these several factors. Great industrial activity creates a demand for oil and its products, and so prices are consequently increased; but the cost of material and labor increases simultaneously. The condition of the money market influences the rate at which discount should be applied to future earnings to determine present worth. A decrease in the price of automobiles, tending to make them more universal, will increase the demand for gasoline, and this in turn will be reflected by higher prices for oil. A coal strike will have a similar effect on prices by creating an increased demand for fuel oil. Improvements in the engineering sciences will decrease operating costs or increase the amount of recoverable oil. Thus it is seen that, while the elements entering into productive value may be few, the factors influencing each are numerous and complicated.

Factors Affecting Exchange Value.—Exchange value depends upon productive value and certain psychological and financial factors. When, for example, a new and prolific oil field is discovered, excitement runs high and prices of oil properties not infrequently soar because of the widespread fever to get into these fields. Operators in their eagerness to enter the new fields desert the old ones and the attempt to sell their holdings results in lower prices. Not every sale reflects normal market conditions. There are forced sales in which the vendor disposes of an oil property at a sacrifice to pay off indebtedness or for other financial reasons. There are sales where there is no change in beneficial interest, and consequently the sales price has no significance.

Other Meanings of "Value."—Economists looking merely at the scientific phase of value and not being directly engaged in the problems of valuation have endeavored to restrict the term "value" to the one meaning of exchange value or "fair market value." Engineers determining values for various purposes and by different methods have used the term "value" with many prefixes, each prefix tending to show the exact sense

in which the term is used. Guernsey, taking the field against the engineers and advocating only one use for the term, says:[1]

> And so we have a cost value, a reproduction value, an investment value, a rate-making value, a taxable value, the adjective in every instance being in effect a confession that what is under consideration is not value, or a fair present value, but something which the adjective distinguishes from it.

However, most of these terms have probably come to stay.

Analysis of Book Value

Correct accounting practice demands a knowledge of the true value of an oil property and its component parts. The value of a property consists of several elements, and if complete books of accounts are kept these elements are shown separately. They are:

1. The value of the oil reserves in the ground.
2. The value of the physical equipment.
3. The value of the oil property for purposes other than oil production.

Leasehold Account.—A company may purchase undeveloped acreage in fee, secure the mineral rights thereon, or lease the land for purposes of oil production only. In the latter case the entire bonus price should be entered as the cost of the oil reserves. If mineral rights are purchased, it may be necessary to distribute the purchase price between the value of the coal or other mineral reserves and the value of the oil reserves. If the property is purchased in fee, a certain portion of the purchase price may have to be allocated to the value of timber lands or for agricultural purposes.

Development, Equipment, and Appreciation.—Until the property is developed and equipped it has no value as an income-producer. A distinction should be made between the cost of development, such as drilling, and cost of equipment, as casing, tubing, engine, and boilers. The latter may possess value after the wells are abandoned, while the cost of drilling has no value other than that associated with the oil reserves. The cost of development may be charged either to expense or to capital, while the cost of physical equipment must be charged to capital The cost of unsuccessful tests and of worthless leases is ordinarily

[1] Guernsey, Nathaniel T.: "Valuation," p. 3. Address given Feb. 4, 1916.

charged off as a loss. If the drilling results in the discovery of valuable oil reserves, the property will have a value in excess of the sum of the purchase price, or bonus, and cost of development and equipment. This additional value or appreciation may be determined by appraisals and in many cases may properly be entered on the books of the company, but it should be kept in a distinct account.

Depletion and Depreciation.—Oil properties are wasting assets. The value of the oil reserves is decreased by the extraction of the oil. This depletion should be determined and charged off annually to the reserve accounts. Instead of writing down the asset value of the oil reserves, it is customary to set up an offsetting account, "Reserve for Depletion." This reserve account is cumulative, the amount charged off annually for depletion being added to it each year. For example, if the value of the oil reserves is $100,000 and the depletion for the first 3 years is $30,000, $20,000, and $15,000 respectively, the reserve account would be $30,000, ($30,000 + $20,000 =) $50,000, and ($30,000 + $20,000 + $15,000 =) $65,000 at the end of the first 3 years respectively. The net book value would be the original value less the reserve for depletion, or ($100,000 − $30,000 =) $70,000, ($100,000 − $50,000 =) $50,000, and ($100,000 − $65,000 =) $35,000 at the end of these years. The physical equipment is depreciating and similar accounts are established for depreciation and reserves for depreciation.

Ultimate Distribution of Book Value.—The value of a property for other purposes than oil production may be subject to depletion or depreciation depending upon the nature of the asset. The following example will show the distribution of value of a given property on the books of an oil company:

Agricultural value (not subject to depletion or depreciation)			$ 20,000.00
Oil reserves:			
Leaseholds	$ 15,000.00		
Less depletion	5,000.00	$10,000.00	
Development	$ 45,000.00		
Less depletion	15,000.00	30,000.00	
Appreciation	$120,000.00		
Less depletion	40,000.00	80,000.00	120,000.00
Physical equipment	$ 60,000.00		
Less depreciation	20,000.00		40,000.00
Total			$180,000.00

Purposes of Valuation

Sales or Purchase.—Oil lands may be valued for such purposes as purchase, sale, operating and engineering procedure, merger, basis of capitalization, loan, and taxation. The *value* to be established and the method of valuation depend upon the purpose of valuation. Earl Oliver discusses sales value in the following words:[1]

> The values of an oil property . . . vary widely according to the use for which it is intended, whether it is from the viewpoint of the speculator, the fraudulent stock promoter, the refiner and pipe line owner, or the oil producer.
>
> The market value of a property is usually a combination of some two or more of these influences, and occasionally a combination of all of them, but we prefer to treat each viewpoint as distinct from the others . . .

Value to Speculator.—The speculator buys where he expects a rapid increase in prices, and that land is most attractive to him where values increase most rapidly. The ability to recognize a boom in its earliest stages is an important asset. During such periods prices increase at an astonishing rate and soon become inflated. The speculator, by buying at a low market and selling at a high one, may realize a handsome profit on a quick turnover. His profits depend upon the knowledge of present exchange values and the ability to predict future exchange values. Little recognition is given to true productive values of the properties.

Value to Promoter and Investor.—The promoter takes advantage of a boom, but in a different manner. He uses the boom and its attendant excitement to advertise his properties. Oil properties possess value to him in proportion to their advertising possibilities.

On the other hand, the prudent investor wishes to know the probable prospective earnings of a company in which he is investing. The average prospectus seems hardly to be written with this object in view. The investor should determine the probable value of his investment prior to investing. If the significant facts for a valuation are not given by the company, the investor should determine them for himself. The altogether

[1] Oliver, Earl: American Institute of Mining and Metallurgical Engineers, February meeting, 1920.

too frequent rule of "Invest first, investigate afterwards" should be reversed.

Value to Operator.—The profit to be derived from the sale of the oil produced determines the value to the oil producer, but the greatest value is attained when the operator and refiner are integrated in one company. In the latter case, the hazards of a producer finding a market and of a refiner obtaining a supply are eliminated. Likewise, the value of a group of leases is more valuable than the same acreage in isolated leases. The drilling of a wildcat well, ordinarily, is not considered unless a large area can be leased and a great reward thus insured if the test be successful. Operating and drilling expenses are greatly reduced, there are savings in line fights and offset wells, and an efficient operating policy may more easily be pursued, as the same overhead and perhaps the same equipment necessary for a small unit may be applied to a larger unit. Where land is of little value for other purposes than oil production it is a common practice for oil companies to purchase the land in fee. This practice eliminates possible conflicts between lessor and lessee. In the foregoing instances the algebraic axiom that "the whole is equal to the sum of its parts" is not true. The whole is greater than the sum of its parts. Upon division into separate elements a certain part of the value is lost.

The profits of an operator depend largely upon his ability to purchase properties at or below their productive value. To do this, it is essential that productive value be determined, otherwise he will not know whether the purchase price is reasonable or not. The application of "rule-of-thumb" methods in valuation is gradually giving place to more scientific methods, and the valuation engineer is becoming recognized as being a practical help in the solution of valuation problems.

Valuation for Business Guidance.—Valuations are required in the business management of an oil concern. Advice may be desired concerning the desirability of flooding the property, use of compressed air, or of vacuum. In all these decisions the most important question is: "Does the prospective return justify the expense?" The answer to the above question involves two determinations: First, what increment is to be added to the value; second, what increment is to be added to cost? The added cost consists of installation costs plus or minus a certain portion of the operating costs, depending upon whether

the old or the new system is more expensive in operation. The probable recovery of oil and its value under the old and new systems must be computed and compared. With these elements determined, the advisability of inaugurating a given system can readily be ascertained.

Valuations for Merger.—In the case of merger the chief desideratum is fairness in apportioning the values of the companies involved. So long as the ratio between the values of the companies is fair, the interests of all stockholders will be protected. Two companies which are to be consolidated may be valued at $1,000,000 and $2,000,000 respectively, or at double these values. The beneficial interest of a given stockholder after consolidation is the same in each case. While the chief interest centers about relative values, actual values should not be neglected, as the appraisals will affect the capital accounts.

Valuation as a Basis of Capitalization.—Where properties are acquired with stock, as at the organization of a company, valuations are required. Unfortunately, oil properties received in exchange for stock are usually overvalued. The valuations are commonly made to agree with the amount of stock that the corporation desires to issue rather than to agree with the true value of the property. Where overvaluations are made, the books of account and the financial statements do not reveal the true condition of the business, and if these accounts and statements are used as a basis for investment, the investor is deceived. In many instances, assets are overvalued in order to induce investment.

Valuations as a Basis of Loan.—Oil companies usually possess but little assets other than oil-producing lands and the equipment thereon. Ordinarily, neither have any great value aside from their income-producing qualities. Loans may be negotiated, using the credit of the company as security or the oil properties themselves as the basis of guarantee. In either case, it is necessary to make conservative valuations of the oil properties. Due consideration should be given to the credit of the company, its management, and outstanding obligations. Provisions made for the payment of the debt should be carefully considered. It is fully as necessary to consider the probable value of the assets at the expiration of the loan as their present value, unless an adequate sinking fund has been provided to amortize the indebtedness.

Valuation and Taxation.—Various types of taxes are based upon or are related to property valuations. Property taxes are usually proportional to the values of the properties, and consequently low values are to the taxpayer's advantage. In the case of income taxes, low valuations reduce the deductions for depletion and depreciation, increase profit from sale of capital assets, and are to the disadvantage of the taxpayer. These valuations may be required as of March 1, 1913, within 30 days of date of discovery in cases of discovery wells, or at date of acquisition, if acquired with stock or as a gift, as well as in other special cases. Valuations for purposes of Federal taxation have assumed considerable importance during the last few years. Much difficulty has been encountered because these valuations in many instances have been made by untrained men. It requires technical training, knowledge of oil properties, and sound judgment to make valuations successfully. In addition, a knowledge of the elements of accounting and of income tax law is required if such valuations are to be made for income tax purposes.

CHAPTER II

THE ESTIMATION OF OIL RESERVES: PRODUCING WELLS

Nature has proved quite indiscriminate in the award of prizes or blanks to those who have expended their money and energy in the search for petroleum. A hundred thousand dollars may be spent in drilling a wildcat well without any remuneration—indeed, the sum may be much greater in foreign fields. On the other hand, single wells may make their owners multimillionaires.

Thompson reports that one well in Russia produced $1,300,000 worth of oil in 1 month in spite of the low prices then prevailing. Within 18 months the Columbia well of the Moreni field, Roumania, produced oil valued at $5,760,000. Within 1 month 3,750,000 barrels of oil were produced from one well at Baku, Russia. In the Campina oil field of Roumania, well No. 65 of the Steau Romana Company ejected 105,000 barrels of oil and 150,000 tons of sand in 30 hours.[1] In Mexico, one well, Cerro Azul No. 4, produced 260,000 barrels of oil daily.[2] In the Jennings oil pool of Louisiana, 1,280,000 barrels of oil were produced from a single well in 4 months.[3] Even in the Pennsylvania oil fields, where wells are noted for their small yield, a single well in the McDonald pool is credited with a yield of more than 2,000,000 barrels.[4] Such yields are exceptional. The more normal yields are 55 barrels a day in California, 5 to 10 barrels a day in the Mid-Continent field, and less than 1 barrel a day in the Appalachian field. December 31, 1922, the average yield per well in the United States was 5.7 barrels.[5]

The productive life of wells and rate of decline in output vary greatly in different areas. In the North Louisiana fields some

[1] Thompson, A. Beeby: "Oil Field Development," pp. 54 and 154.

[2] Beal, Carl H. and Lewis, J. O.: Some Principles Governing the Production of Oil Wells, U. S. Bur. Mines, *Bull.* 194.

[3] "Mineral Resources of the United States for 1904," *U. S. Geol. Survey*, p. 708.

[4] "Manual for the Oil and Gas Industry," published by the U. S. Treas. Dept., p. 101. 2nd ed.

[5] Compiled from figures prepared by the U. S. Dept. of Interior.

wells with initial productions[1] as high as 3,000 barrels have produced half of their oil within the first month. In Pennsylvania, where initial productions are not high, wells have produced for 20 or 30 years. In Tulsa County, Oklahoma, one well, which was rated as a 4-barrel pumper when completed, has produced for 20 years.

STATISTICAL BASIS

Compensating Errors

Fortunately, there are guides which assist in the prediction of reserves of undeveloped acreage and the future yield of producing wells. These guides are most serviceable where a large number of cases are considered, because the errors may then be compensating.

In a given case, unusual circumstances may cause a considerable departure from average or normal conditions either in the production of a given well, the initial production of a new location, or the yield of various types of geological structures. If such adventitious circumstances continue to occur, as is quite likely, individual predictions based on these averages may be considerably in error. Some estimates will be too high, others too low. However, if predictions are made in a hundred cases many of the errors will compensate each other, and the percentage of errors will be materially reduced. An error in an individual case may be due to the occurrence of some abnormal condition, or to an incorrect analysis of the situation. Errors which persist through a large number of cases must be attributed to the latter cause.

Types of Averages

Definitions.—Production-decline curves, yields per acre-foot, cost, and other data necessary in valuing oil properties are based upon averages. In all cases where use is made of an average, it is advisable to consider which of at least three central tendencies should be used. These are the arithmetical mean, the mode, and the median. The arithmetical mean may be defined as the total of all the numbers divided by the number of numbers. The mode is the number occurring most frequently. The median is that number which divides the numbers into two

[1] The term "initial production" will be used to denote the actual or estimated production of a well for the first 24 hours, unless otherwise noted.

equal groups. In the group of numbers 4, 10, 2, 52, 5, 4, 25, 12, 9, 3, 7, 6, 4 the arithmetical mean is

$$\frac{4+10+2+52+5+4+25+12+9+3+7+6+4}{13} = 11.$$

The mode is 4, as it occurs three times out of a total of 13, and no other number occurs more than once. The median is 6; there are six numbers less than 6 and six numbers more than 6. Assume that an arbitrary selection of one number is made from a group of numbers such as those above. There is an equal chance that the number thus selected is greater or smaller than the median. This characteristic has frequently but erroneously been attributed to the arithmetical mean. In the foregoing group, 25 and 52 are erratic numbers. After their elimination, the mode will remain 4, the arithmetical mean (the average most generally used) will be reduced from 11 to 6, while the median will be changed from 6 to 5. The occurrence of an erratic number will produce the greatest effect upon the arithmetical mean and the least effect upon the mode.

Effect of Field Conditions.—Applying this thought to a group of wells, the elimination of the unusual well is conservative practice, but in some cases it is ultraconservative. For example, consider the estimation of production from a limestone containing oil both in solution cavities[1] and in pore spaces.[2] Whenever a solution cavity is penetrated, a well of unusual volume is the result. This, however, may occur once in every 10 or 20 drill holes and yet, while not typical, these wells may be the chief source of profit. To eliminate them from consideration might result in the condemnation of a very valuable property. In such cases the arithmetical mean rather than the mode should be used.

[1] Solution cavities are openings formed in rock by the dissolving action of water. They are particularly common in limestone and may attain enormous size. The Luray Caverns, Virginia, and the Mammoth Cave, Kentucky, both occurring in limestone formations, are examples. Oil may readily be extracted from such openings.

[2] The term "pore space" as here used will refer to openings of small size which are distributed quite generally throughout a given rock. These openings occur between the grains, as in sands or sandstones, or may be caused by the shrinkage of a rock. If a fairly pure limestone is changed to dolomite without addition of carbon dioxide, there is a shrinkage of about 12 per cent. Capillarity prevents the rapid extraction of oil from such openings.

Consider a property in which drilling is in active progress. As new wells are drilled, the drainage areas tributary to a given well become smaller. Interference becomes established; that is, the new wells drilled reduce the yield of the old wells by diverting the flow of some of the oil to themselves. If the first well drilled on such a property results in an unusually large output, its exceptional yield may be attributed to possession of a large drainage area and to lack of interference. The consideration of the large output from such wells would be a decided source of error when predicting the production of new wells.

Average to Be Used.—Very evidently the inclusion of the exceptional well in any statistical study depends largely upon its likelihood of being repeated in further drilling. Since the mode is not affected by the exceptional case, it is of especial advantage when considering only a few wells, or when the exception is not likely to repeat itself. As the mean is greatly affected by the exception, its use is most advisable when considering a large number of properties where the exception is likely to be repeated.

When making single estimates, it may be desirable to assume that conditions are typical, and endeavor to predict accordingly. No attempt should be made to estimate the future production of a typical well from a curve based on the arithmetical mean, as results are likely to be disappointing. In such cases the mode should be used as the basis for prediction. Where conditions are not typical, the mode can also be used by making whatever adjustments may be necessary. No additional allowance should be made for the exceptional case when using a curve based upon mean conditions, as any such allowance has already been considered in forming the curve. It is advisable to remember that the normal well is below the mean, and that the latter has only been maintained because of the exceptional well.

Application to Curves.—In the following discussion of the methods of compiling composite curves,[1] the exceptional well has been eliminated and the method of the arithmetical mean applied to those remaining. A true mean may be obtained by including the exceptional well. Beal's graphical "family curve" method of making composite curves lends itself readily to the application of the mode by drawing a line where the individual production-decline curves are thickest.

[1] By a "composite curve" is meant a curve formed by combining two or more records either of individual wells or of tracts.

FULLY DEVELOPED TRACTS

There are three separate groups or classes of properties for which reserves must be computed. They are (1) fully developed tracts, (2) partially developed tracts, and (3) entirely undeveloped tracts. The procedure is different in all three cases and will be considered in the order named.

Fully developed tracts may be defined as tracts upon which further drilling is unprofitable; whether or not any profit will be derived from further drilling is dependent upon a number of factors, among which is the price of oil. A tract considered fully developed when the price of oil is $1 a barrel may be the scene of profitable drilling activity if the price is advanced to $2 a barrel. Likewise, the discovery of a new oil sand on a tract considered fully developed results in further drilling activity, and the new wells drilled may greatly increase the profit of the operator. In determining whether a tract is fully developed or not, only known facts and reasonable assumptions should be considered. The spacing of wells to be attained before a tract is considered fully developed will be discussed in the next chapter.

When estimating oil reserves of fully developed properties, attention is confined to the producing wells. These estimates are most readily computed by means of production curves in cases where they are applicable. Ratios of future production to that for a given period, as a year, may also be used.

CHARACTERISTICS OF PRODUCING WELLS

Typical Decline of an Oil Well.—Ordinarily, the rate of production is greatest when the well is first completed. From that time to date of abandonment the production declines, except as changed operating conditions may cause an increase. However, if wells with great initial production and high gas pressure obtain their production from unconsolidated sands, the well may drill itself in, that is, production may increase for a short time before the decline begins. The rate of decline is usually greater with large wells than with small ones. The decline is rapid at first during the period of "flush production" but becomes much slower during the period of "settled production."[1] The past

[1] Operators are accustomed to dividing production into "flush production" and "settled production." The term "flush production" is applied to the rapidly declining output occurring in the early history of a well. The term "settled production" is applied to the output of the later years, where

production of a well and of similar wells forms the basis for estimating future production. This prediction is usually made graphically, and is based upon the assumption that production declines in a symmetrical manner, with a constantly decreasing decrement, and that graphical extrapolation can be applied to the known data.

Oil Reservoirs.—The correctness of this assumption depends in a large measure upon the natural forces controlling the expulsion of petroleum and upon the character of the reservoir, whether the oil and gas have accumulated in pore spaces in sandstone, solution cavities in limestone, or joint crevices in shale. If oil exists in free openings, as in the last two examples, it can be extracted as rapidly as the pump can work until the supply is exhausted. Should the supply exist in the pores of a sandstone, capillary attraction will prevent the free flow of oil into the drill hole and it cannot be pumped out faster than it is forced into the bottom of the well by the natural expulsive forces acting upon the oil.

Gas Pressure.—The chief expulsive forces are gas pressure and hydrostatic pressure. Both may be influenced by the force of gravity. Gaseous hydrocarbons are commonly dissolved in petroleum, but only under pressure, and tend to escape wherever there is an opening such as is furnished by a drill hole; in their escape they may assist in the extraction of the petroleum. Their force is greatest when the oil reservoir is first tapped, and gradually diminishes as the gas pressure becomes less. Under these circumstances, the rate of the extraction of the oil, dependent in a large measure upon the expulsive forces, becomes less and less.

Hydrostatic Pressure.—Water and oil frequently exist in different parts of the same reservoir, the oil occupying the higher portions. The water may be under considerable pressure, which

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there is but slight decrease in the production of oil. Although no sharp distinction exists between the two, many instances occur that can readily be grouped into one or the other. If the decline in production for the early years of a well is 50 per cent or more annually, there would be no hesitancy in calling such production "flush." On the contrary, there are wells in the Appalachian field which have produced one or two score years and where the annual output is nearly constant; the production from such wells would unhesitatingly be called "settled." Between the two, all possible variations exist.

it transmits to the oil; as the oil is extracted the water moves up to take its place. If the openings in the rock are large, this movement may occur with but slight reduction in hydrostatic pressure. Production may be maintained at a nearly constant rate until the water reaches the well and causes its abandonment. The wells near the edge of the producing area, namely those located low structurally, first feel the effects of water encroachment. This encroachment proceeds inward, drowning successively the wells located higher and higher structurally. The date at which the abandonment of a given well may reasonably be expected can be determined from the rate of the advance of the water.

Application to Curves.—Production curves, therefore, may fully apply when oil exists in the pores of rocks such as sandstones, sands, or porous limestones, and when the chief expulsive force is gas pressure. In other cases the decline curve method is not applicable; but fortunately the conditions that permit of its use are widespread, although, as noted, not universal.

PRODUCTION-DECLINE CURVES

Curves may be drawn showing the production of either wells or tracts. They may be prepared from the production record of a single well or tract, or several production records of tracts or individual wells may be combined into one curve. There are several types of curves, which may, however, be classified into three groups: (1) production-decline curves, (2) cumulative production curves, and (3) comparative production curves.

Construction of Production-decline Curves

By a production-decline curve is meant any curve in which time and production are plotted as the two variables. Such a curve is shown in Fig. 1. The scale to the left of the figure indicates the production in barrels; those to the right indicate the production as percentages of (*a*) ultimate production and (*b*) the production of the first year. The figures indicating the yearly production are printed at the appropriate places on the curve; the years, or time element, are indicated at the bottom. The chief use of a production-decline curve is to assist in the prediction of future production of the same or some other well or

property. Very evidently, then, it becomes necessary to extend a curve beyond the period of known production. This extrapolation is done graphically, either from curves drawn on quadrille paper,[1] or from curves drawn on logarithmic paper.[2]

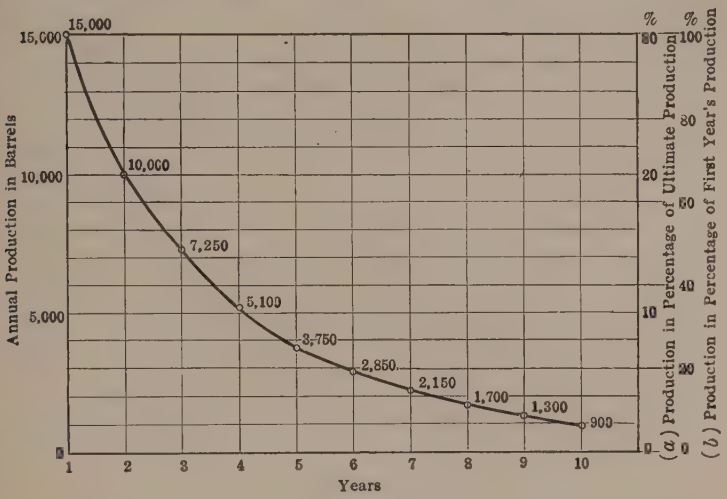

FIG. 1.—A decline curve.

Extrapolation on Quadrille Paper.—The plotting of past production on quadrille paper enables one to use the peculiarities of the individual well and the trend of production in extrapolation. Figure 2 is an illustration of this method. The heavy line and circled dots represent actual production, the dashed line represents the generalized curve, and the dotted line the extrapolation. The curve should be so extrapolated as to form one continuous smooth curve, which is typical of the

[1] Quadrille paper (sometimes called "coordinate paper") is paper on which two sets of parallel and equally spaced lines intersect each other at right angles. (For an example see Fig. 2.)

[2] Logarithmic paper is paper on which two sets of parallel lines intersect at right angles, the distances between the lines being based on the logarithms of those numbers which the line represents. Lines representing a geometric progression are equally spaced. Thus one finds equal intervals between lines representing any of the following series of numbers: 1, 10, and 100; 1, 2, 4, 8, and 16; or 1, 3, 9, and 27. Figure 3 shows this type of paper. The mathematical properties of logarithmic paper render it particularly valuable in plotting decline curves and predicting production.

general decline of similar wells. A necessary prerequisite to such extrapolation is a correct mental picture of decline curves. Actual comparison may advisedly be made with decline curves of similar individual wells whose histories are known, or with composite curves of several wells. The entire curve must be smooth and without any sudden changes in curvature. The previous history of the well and its peculiarities, the length of life of similar wells in the field and their probable decline, the history of the

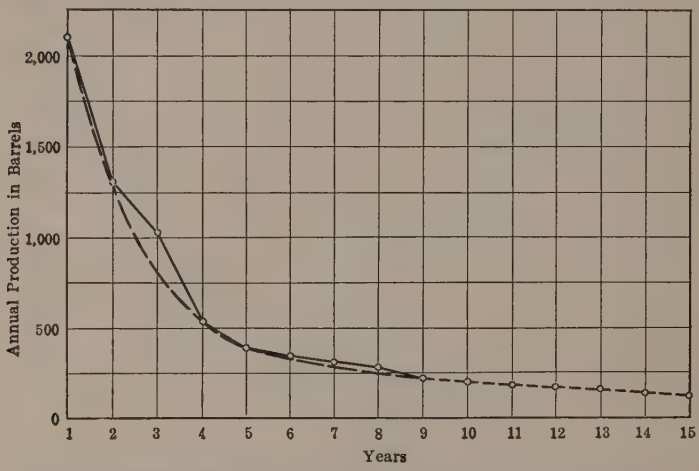

FIG. 2.—Diagram illustrating the extrapolation of a production curve on quadrille paper. The solid line indicates actual production, the dotted line the extrapolation, and the dashed line the generalized curve.

development of the field, and its relation to interference should all be considered.

Extrapolation on Logarithmic Paper.—Logarithmic paper may be used in some cases for the extrapolation of a curve. However, considerable care must be exercised in its application, as errors are greatly magnified when plotted on this paper. Its use should be confined to curves that are regular or which have previously had their irregularities reduced. The use of logarithmic paper is best adapted to curves compiled from a large number of individual well records extending over a long period of time.

Decline curves can frequently be plotted as a straight line in one position on logarithmic paper; but this is true of one position only, which may be determined by trial. Extrapolation is then made by the continuation of this straight line. Figure 3

shows the production-decline curve in three positions. The correct position is shown at *AA* and the dashed line indicates the extrapolation. Positions *BB* and *CC* show the production record plotted as curved lines. All points of such curves should be moved an equal number of spaces in the direction of their

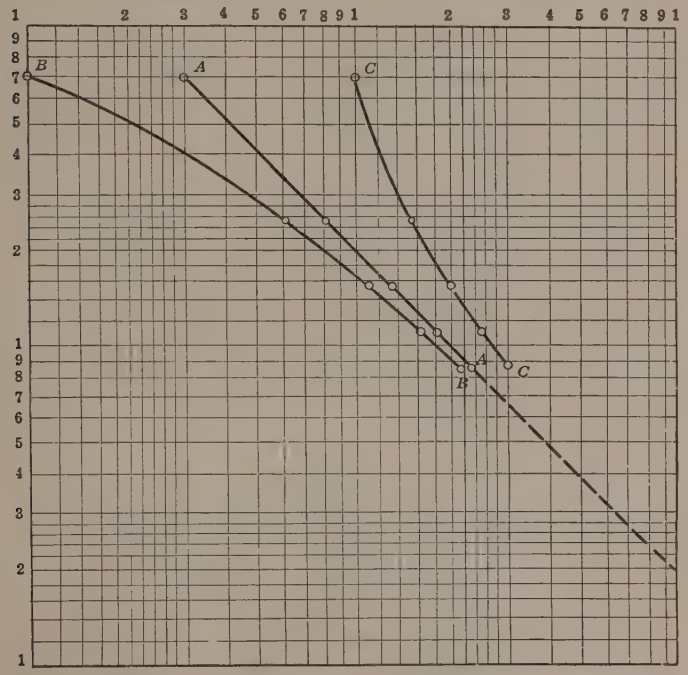

FIG. 3.—Diagram illustrating the method of extrapolation of a production decline curve on logarithmic paper. *AA* shows a curve in the correct position, the dashed line shows the extrapolation as a straight line. Incorrect positions for extrapolation are shown by curves *BB* and *CC*.

convex side. Reducing the horizontal scale has the same effect as shifting the graph to the right.

Production-decline curves may be plotted as a straight line on logarithmic paper and the coordinates of two points determined. These coordinates may be recorded for future reference and the entire curve reproduced on logarithmic paper as required. Reference space given to such curves can thus be materially reduced. The coordinates of the curves given in the "Manual for the Oil and Gas Industry" may be found in the Appendix.

Irregularities in Production-decline Curves

The production-decline curves shown in Figs. 1, 2, and 3 have few, if any, irregularities. Extrapolation from such curves is comparatively easy, but unfortunately the records which must be used in actual practice commonly have many irregularities, and even those which are regular may be deceiving if not correctly interpreted.

Irregularities may be due to several causes. Adventitious influences are relatively more important when the production-decline curve is based on a short time unit. For this reason daily production curves may have but little meaning. It may be

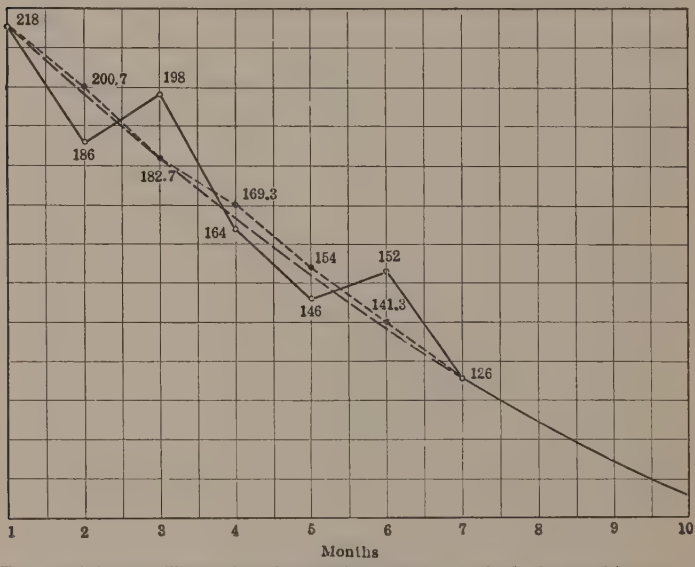

Fig. 4.—Diagram illustrating the running average method of smoothing out a production decline curve.

necessary to employ the month or quarter as a time unit if the production records cover only a short period. When the period covered by past production records is sufficiently long, the year is undoubtedly the best unit.

Reduction of Irregularities by Running Averages.—Irregularities in a curve may sometimes be reduced by using running averages. Each point is averaged with the preceding and succeeding

point, the first and last points being omitted unless they fit into the curve. Figure 4 illustrates this method. The monthly production for a given well is as follows:

Month	Barrels
First	218
Second	186
Third	198
Fourth	164
Fifth	146
Sixth	152
Seventh	126

Each point is plotted and enclosed by a circle, these points are then connected by a solid line. Points are determined for every month from the second to the sixth inclusive, as follows:

$$\text{Second month } \frac{218 + 186 + 198}{3} = \frac{602}{3} = 200.7$$

(It will be noted that the above numbers, 218, 186, and 198, represent the production of the first 3 months.)

$$\text{Third month } \frac{186 + 198 + 164}{3} = \frac{548}{3} = 182.7$$

$$\text{Fourth month } \frac{198 + 164 + 146}{3} = \frac{508}{3} = 169.3$$

$$\text{Fifth month } \frac{164 + 146 + 152}{3} = \frac{462}{3} = 154$$

$$\text{Sixth month } \frac{146 + 152 + 126}{3} = \frac{424}{3} = 141.3$$

The points determined by the running averages are plotted as dots and connected by dotted lines to each other and to the end points, which, in this case, fall in line. This curve is still somewhat irregular and, consequently, a third dashed line is drawn to indicate the general decline in production. This line has no irregularities in it but follows as closely as possible the line of the running averages. The method of running averages can be employed by taking the average of more than three points, but only one resultant line can be obtained on a given basis.

Reduction of Irregularities by Equal Areas Method.—Irregularities may also be reduced by the method of equal areas. A smooth curve is drawn intersecting the line indicating actual production. Areas will thus be formed of which these lines are

boundaries. The method consists in so drawing the smooth curve that the area below this line shall equal the area above the line.

In Fig. 5 the light line connecting the points enclosed in circles represents the actual production; the smooth heavy line represents the general trend of the decline. The areas *A*, *B*, and *C* are bounded by these two curves. The sum of the areas *A* and *C* above the line is equal to the area *B* below the line.

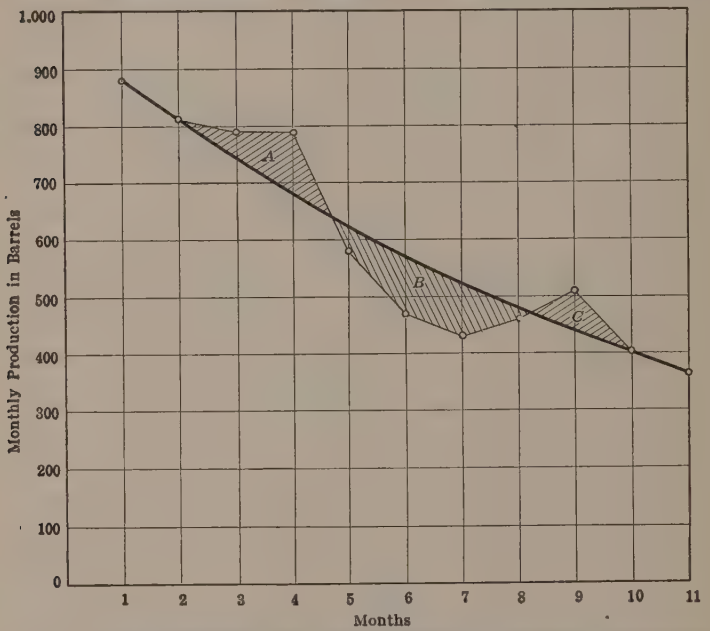

FIG. 5.—Diagram illustrating the equal area method of smoothing an irregular curve. The area *B* is equal to the sum of areas *A* and *C*.

The method of equal areas permits the drawing of a number of smooth lines each having different curvatures but equal areas above and below the line. That curve should be selected which most closely follows the line of actual production or which most closely follows the decline of similar wells.

Irregularities Due to Drilling Activity.—In some cases production from each well is run into separate tanks. It is then possible to obtain production records for individual wells, but usually this is not the case. The production from an entire

lease, from small wells and large wells, from those yielding flush production, and those which are old and with settled production may all be run into one tank. The only records available are the production records for the entire tract, and when drilling is in progress the production of a given tract may increase while the production of the individual wells is declining. The determination of the production per well overcomes this difficulty in a measure, but great differences may exist between the production of the average well[1] and of a typical individual well.

The effect of drilling activity upon the production of the average well is dependent upon the initial production of new wells. If the new wells have an initial production in excess of the average production per well, the production of the average well may increase, as shown in Fig. 6. On the contrary, if the production of new wells is only slightly in excess of the average production, the effect of the sustained production[2] may be slight and the curve of the average well may closely follow that of a typical single well. The effect of bringing in a well with a smaller production than average is shown in Fig. 7. Figure 8 shows a regular curve but the effect of sustained production is present nevertheless. Figure 9 shows a break in the decline curve when no more new wells are drilled.

Effect of Large Wells.—Figure 6 shows the production curve of an average well. The encircled numbers indicate the number

[1] The term "average well" is used to refer to a hypothetical well the production of which equals that obtained by dividing the total production by the number of producing wells.

[2] When wells are drilled, the production of the tract, and usually that of the average well, is in excess of the production that would have been obtained if no new wells had been drilled. Assume that without further drilling the production for the first 3 years would be 100,000, 50,000 and 30,000 barrels respectively, but due to the drilling of new wells the actual production is 100,000, 70,000, and 55,000 barrels for these years. In both cases production declines, but the rate of decline is less when new wells are drilled. The difference in production under these two sets of conditions is 20,000 barrels the second year and 25,000 barrels the third year, which represents the amount of sustained production. Sustained production may be defined as the production obtained when new wells are drilled less the production which would have been obtained had no such wells been drilled. It is evident that total tract production is sustained whenever new producing wells are drilled; however, the drilling of new wells may or may not result in sustained production of the average well. (See further discussion in the text and Figs. 6, 7, 8, and 9 concerning the effect of drilling activity upon the average well.)

of producing wells on the tract. It will be noted that there were two producing wells for the first 5 years, and that during this period the decline was fairly uniform. The sixth, seventh, and eighth years show 3, 5, and 6 wells respectively, indicating renewed drilling activity. The production from the new wells was greater than that from the old ones, thereby increasing the

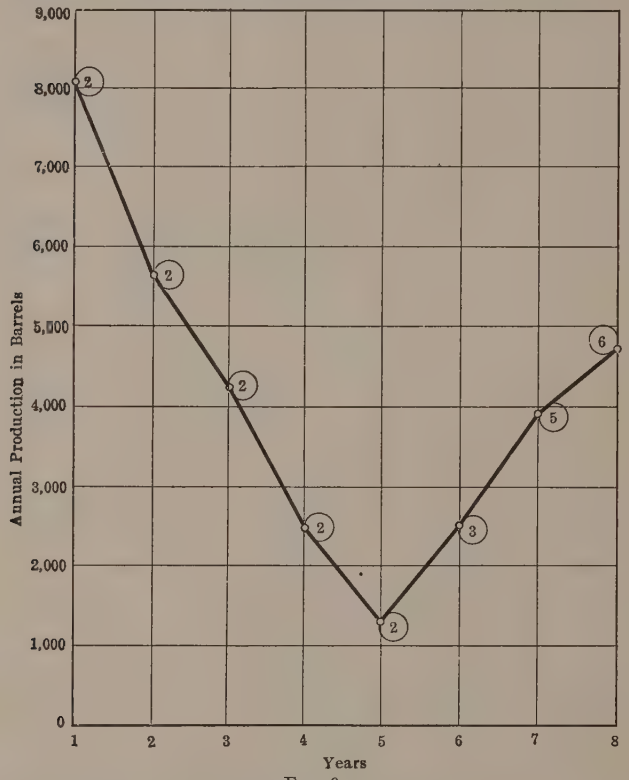

FIG. 6.

average production per well as shown in the figure. It would be exceedingly foolish to predict a continuously increasing production based upon the production for the last 4 years. The future yield of the six wells now operating should be based upon the regular decline indicated by the two wells producing for the first 5 years. Any allowance for production from new wells should be made separately.

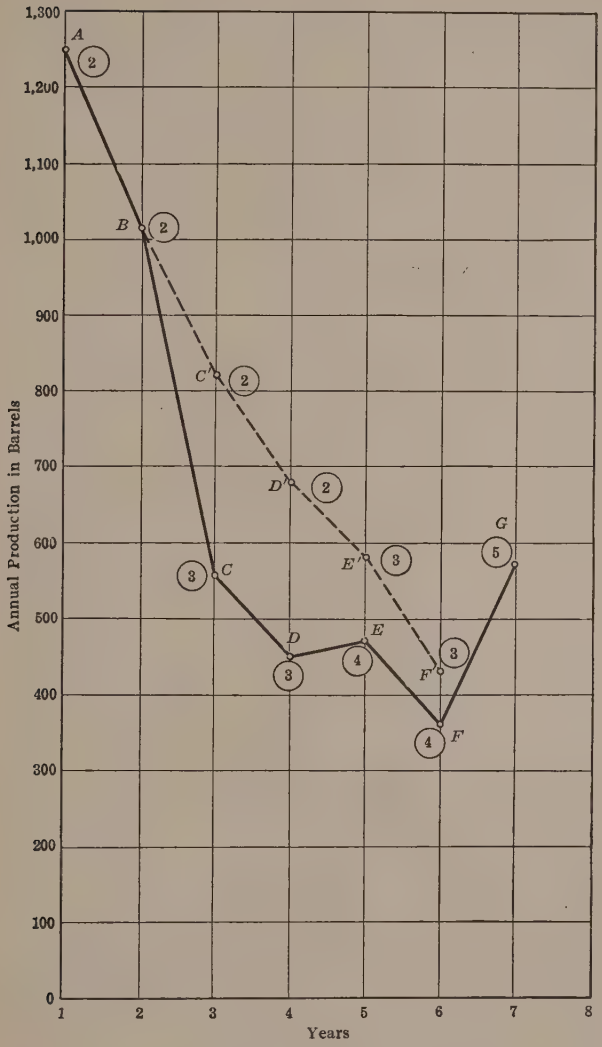
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
Annual Production in Barrels
1
2
3
4
5
6
7
8
Years
A
B
C
D
E
F
G
C'
D'
E'
F'
2
2
2
2
3
3
4
3
4
5

FIG. 7.

Effect of Small Wells.—The completion of a poor well may introduce irregularities into the production-decline curve of the average well. Such a well, while contributing but little to total production, requires the distribution of the production of the tract to one more well. Figure 7 illustrates such a case. The third well completed contributed but little production. Curve *ABCDEFG* was obtained by dividing the annual production for the tract by the number of producing wells, indicated by the encircled numbers. The curve *ABC'D'E'F'* was obtained by dividing the annual production of the tract by the number of wells which would have been producing if well No. 3 had not been drilled or had been a dry hole. The number of such wells is indicated. Ignoring well No. 3, as in the last method, is not only logical but results in a curve which can be used to better advantage in making estimates of future production.

It will be noted that in Fig. 7 there is a material increase in the average production from the sixth to the seventh years. This is due to the completion of a large well in the seventh year.

Sustained Production.—The production-decline curve of the average well may be regular and yet not be typical of an individual well. The fact that the curve is sustained by flush production may easily be overlooked because of its regularity. In Fig. 8, *A* is the curve of an individual well and *B* of the average well. Curve *A* is based upon a well having the following yearly production:

Year	Barrels
First	10,000
Second	5,000
Third	3,500
Fourth	2,500
Fifth	2,000
Sixth	1,700
Seventh	1,500

If a tract contains any number of wells all having the same production and all beginning to produce on the same date, the average production per well would be the exact equivalent of the production of a single well. If, on the contrary, each well had the same production but a year intervenes between the drilling of successive wells, then the decline of the average well will bear little resemblance to that of the individual well. Based upon this assumption the computation of the average production per well indicated by curve *B* is given below:

Well No.	First year	Second year	Third year	Fourth year	Fifth year	Sixth year	Seventh year
1	10,000	5,000	3,500	2,500	2,000	1,700	1,500
2	.....	10,000	5,000	3,500	2,500	2,000	1,700
3	.....	.....	10,000	5,000	3,500	2,500	2,000
4	.....	.....	.....	10,000	5,000	3,500	2,500
5	.....	.....	.....	.....	10,000	5,000	3,500
6	.....	.....	.....	.....	.....	10,000	5,000
7	.....	.....	.....	.....	.....	.....	10,000
Total for tract.....	10,000	15,000	18,500	21,000	23,000	24,700	26,200
Total wells producing.....	1	2	3	4	5	6	7
Average production per well (Upon which curve *B* is based.)	10,000	7,500	6,133	5,250	4,600	4,116	3,743

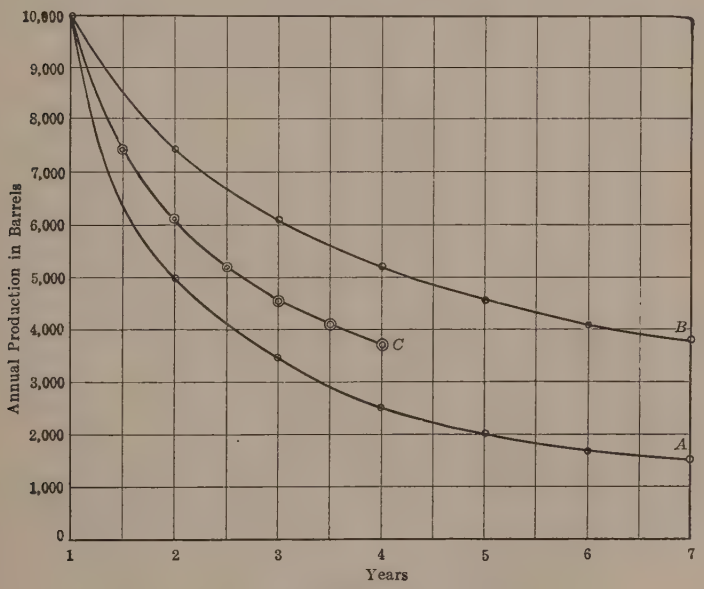

FIG. 8.

The sustained production of curve *B* as contrasted with curve *A* is due to the yearly increments of flush production. The

production of the tract for a given year is obtained from wells of various ages. At the end of the third year, one well had been producing 3 years, another 2 years, and a third 1 year. The average age is 2 years. Similarly, the average age of the producing wells for each year in the history of the tract can be determined, and is here given.

Age of production computed from date of first completion (a)	Average age of producing wells (b)	Average production per well for year (c)
1	1	10,000
2	1½	7,500
3	2	6,133
4	2½	5,250
5	3	4,600
6	3½	4,116
7	4	3,743

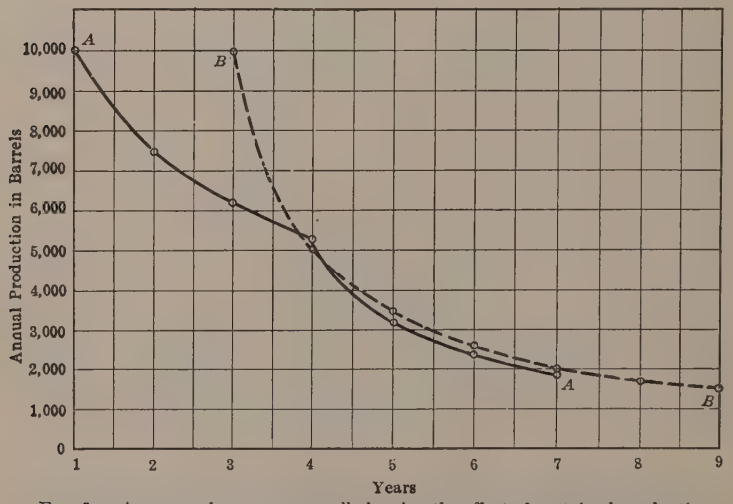

FIG. 9.—*A*, curve of an average well showing the effect of sustained production for the first four years due to active drilling of new wells; the break in the curve at the end of the fourth year is due to cessation of drilling activities. From the fourth to the seventh year the curve follows fairly closely that of an individual well. *BB*, curve of an individual well.

Columns (a) and (c) form the coordinates of curve *B*, and columns (b) and (c) of curve *C*. By comparing curves *A*, *B*, and *C* it can be seen that the effect of sustained production is greatly reduced but not entirely eliminated by plotting production upon the basis of the average age of the producing wells rather than upon the age of the oldest well. When no new wells are drilled, a distinct break in the average well curve may be found. This condition is shown in Fig. 9, curve *A*. No new wells were drilled after the fourth year. This accounts for the break at the end of that year and for the great decline in the production from the fourth to the fifth years. With cessation of drilling activity the average production per well nearly follows the typical decline of the single well. The curve of an individual well is shown by the dashed line *B*.

Irregularities Due to Abandonment.—The average production per well may be increased when poor wells are abandoned, as

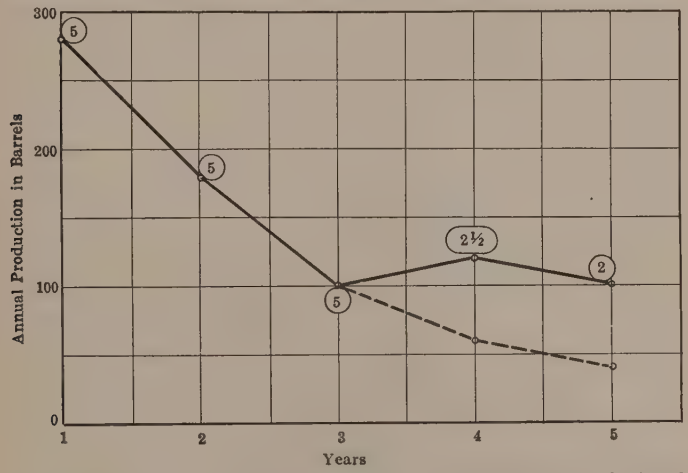

FIG. 10.—Solid line shows how the abandonment of poor wells in the fourth year caused an increase in production of the average well. The encircled numbers indicate the number of producing wells. The dotted line indicates one-fifth of the tract production.

shown in Fig. 10. Five wells are indicated as producing the first 3 years, but some are abandoned in the fourth year. The total production for the fourth and fifth years is divided by the average number of wells, namely 2½ and 2 wells, respectively. This result is shown by the solid line. The total production for

these 2 years divided by 5 is shown by the dashed line. It is apparent that the increase of the average well (shown by the heavy line) is due to the abandonment of small producers which were not material factors in the production of the tract. In this case a more typical curve of the actual decline is obtained by disregarding the abandonment of the small wells in the fourth year and using 5 as the divisor throughout.

Where the foregoing conditions exist it is advisable to use tract production without reducing to the average well basis. This procedure is both simple and helpful in predicting production.

It is apparent that care must be exercised in using a curve of an average well when wells are either being drilled or abandoned. A study of the initial production of new wells may assist in determining the extent to which the production of the average well is modified by the completion of the new wells. If the initial production of new wells is found to be materially in excess of the average well production, the curve of the average well most probably represents sustained production. If the initial production of new wells approximates the production of the average well, the average well curve is not greatly modified. If the initial production of new wells is less than the average well, the curve of the latter is steepened.

Irregularities Due to Methods of Operation.—Irregularities in the curves may be due to changes either in the method of extraction or in the efficiency with which the method is applied. Increased production may result from the cleaning or shooting of a well. In times of high prices greater emphasis may be placed upon efficient methods of operation and an increase in production may be the result.

Three processes have been employed for increasing the extraction of oil; application of partial vacuum to producing wells, flooding the producing sand with water, and forcing air under pressure into the oil sand. The successful application of these methods is based upon the following principles: The application of vacuum to the mouth of the well reduces the back pressure and renders the gas pressure more effective in expelling the oil. The introduction of water into the oil sand displaces the oil, much of which may be forced to the mouth of the well and so recovered. Forcing air into the oil sand under pressure renews the gas pressure, which is ordinarily the chief expelling force. These methods, however, are not as simple in operation as these

brief statements might imply; in many instances they are not profitable and, indeed, so far, they have been employed to a very limited extent.[1] The increased production due to the inauguration of any of these systems cannot be predicted from the previous decline of the well. Comparison with other wells where the system has been installed may be helpful. However, after the application of vacuum or of compressed air, production-decline curves based upon decline in production since the system was installed can be used, provided the pressure is kept constant.

Effect of Vacuum.—Lewis[2] summarizes the effects of the application of vacuum as follows:

It temporarily increases production, but likewise increases expenses and operating troubles correspondingly, so that it seldom pays except

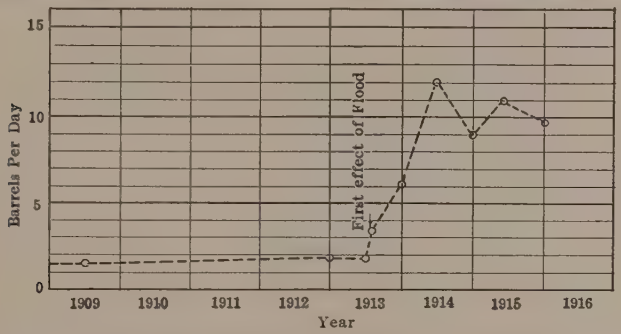

FIG. 11.—Production curve of a property affected by flooding in the Bradford field. Previous to August, 1913, there were 10 wells, later 2 new wells were drilled and an old well abandoned. Most of the oil comes from 2 wells, one 263 feet from the flood well. The property was first drilled in 1879 and is in the center of the field. An adjoining tract was too poor to produce, and recently 3 wells drilled were unprofitable. It has not been affected by the flood. (*After Lewis*).

where profits are derived from an increase in the volume and richness of the gas. The method hastens the recovery of the oil, but the total recovery is only slightly more than that by ordinary pumping methods.

However, the application of vacuum under proper conditions is considered much more favorably by some engineers. Ultimate recovery has been estimated to have increased materially in some cases.

[1] For a thorough discussion of these methods see "Methods for Increasing the Recovery from Oil Sands," by J. O. Lewis, U. S. Bur. Mines, *Bull.* 148.

[2] LEWIS, J. O.: Methods for Increasing the Recovery from Oil Sands, U. S. Bur. Mines, *Bull.* 148, p. 35.

Effect of Flooding.—The successful application of flooding has been confined almost entirely to the comparatively uniform Bradford sand of the Bradford field. Water is allowed to enter and flood the sand; wells in the direction of the advance of the water show an increased production of oil as they come under the influence of the flood. A production curve for such a well, indicating a fivefold increase in production, is shown in Fig. 11.

After a well has come fully under the influence of the flood the production remains fairly constant until the well suddenly goes to water. The use of a production-decline curve as a basis of estimating future production is an impossibility.

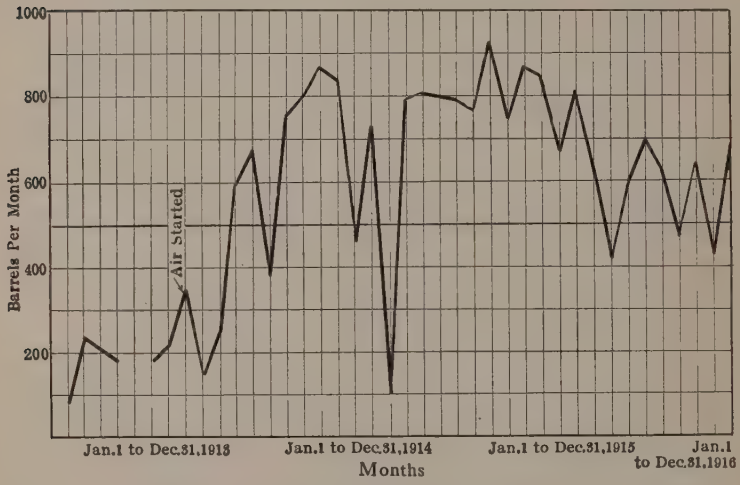

FIG. 12.—Production curve of a property showing the effects of using compressed air. (*After Lewis*).

In the Bradford field of Pennsylvania the drilling of new wells slightly in advance of the flooding water is necessary, as the water ordinarily travels only 50 or 100 feet a year; it will take several years to flood completely even a small property of but 20 or 40 acres. Elsewhere, in more porous sands, the rate of advance may be more rapid. The production of "flooded wells" prior to their abandonment may serve as an index for the production of those wells not yet abandoned. Production per acre may be determined for areas which have been flooded

and abandoned; such yields may be used as the basis for computing the future production of other areas when once they come under flood.

Effect of Compressed Air.—Compressed air has been applied most successfully to the First Cow Run sand of southeastern Ohio and the Big Lime near Woodsfield, Ohio. These sands are coarse and lenticular and hence adapt themselves well to this method. The increased production is indicated in Fig. 12. In 14 properties production was increased on the average nearly fourfold, but Fig. 13 shows that even this increase was not suffi-

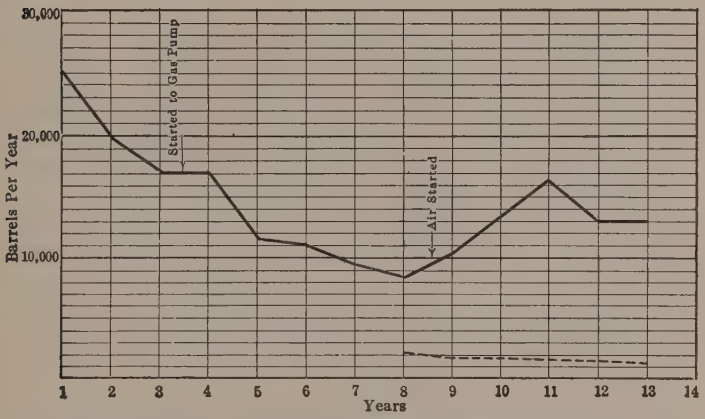

FIG. 13.—Production curve showing the effect of using compressed air. The lower broken line is the production curve of a part of the property on which air has not been used. Compare the effects of gas pumping with the effect of using compressed air. (*After Lewis*).

cient to restore the properties to their original production. Many irregularities in the decline of the average well can readily be explained, but a necessary prerequisite to their correct explanation is a knowledge of their various causes. The drilling history and changes in methods of operation must be known.

COMPOSITE PRODUCTION-DECLINE CURVES

It frequently is found desirable to combine production-decline curves of tracts or individual wells. A curve thus prepared covers a much wider range of production, and compensating

errors tend to reduce irregularities. Only production from the same pool and same sand should be used in the preparation of a given curve. Differences are frequently found in the decline of wells in different parts of the same pool; these differences may form the basis for still further classification of production records if such refinements are desired.

Law of Equal Expectation.—Beal proposed that wells be classified according to size, and, after having made considerable study of the subject, presented the Law of Equal Expectations. He stated this law as follows: "If two wells under similar conditions produce equal amounts during any given year, the amounts they will produce thereafter, on the average, will be approximately equal, regardless of their relative ages."[1] This law furnishes the basis for the prediction of the production of one well by comparison with another. It also gives the basis for classification of wells according to size when forming composite curves. Several methods of grouping wells, using their size as a basis, have been evolved, two of which will be described. The family curve method, first employed by Beal, is graphical, while a second method, first employed by Cutler, is mathematical.

Graphic Method.—The family curve or graphic method consists of plotting each individual well or each average well, in case tract records are used, and combining them into one graph. Wells are plotted in the order of their size and each well is started with the production for the initial period on the line indicating the central tendency for the entire group. The following description of this method is from the "Manual for the Oil and Gas Industry," published by the United States Treasury Department.

Figure 14 illustrates the method of combining production-decline curves for separate tracts in the same field producing under similar conditions, to construct an average-production decline curve for the average well of all the tracts. In this case there were available records of seven tracts, giving the total yearly production and the number of wells producing each year from each tract. See table following.

The yearly production of the respective tracts was divided by the number of wells producing each year on each tract to obtain the yearly production of the average well.

The following table shows the production records of the seven tracts, from which the average production-decline curve in Fig. 14 is constructed.

[1] "Manual for the Oil and Gas Industry," published by the U. S. Treas. Dept., 1st ed., p. 72; 2d ed., p. 73.

TABLE I.—ILLUSTRATION OF GRAPHIC METHOD

	Calendar year—					
	1915	1916	1917	1918	1919	1920
Tract No. 1:						
Total yearly tract production	.....	.....	.....	92,760	43,000	15,200
Number of producing wells	.....	.....	.....	10	10	10
Average yearly production per well	.....	.....	.....	9,276	4,300	1,520
Tract No. 2:						
Total yearly tract production	.....	.....	.....	63,532	54,180	42,960
Number of producing wells	.....	.....	.....	7	9	8
Average yearly production per well	.....	.....	.....	9,076	6,020	5,370
Tract No. 3:						
Total yearly tract production	82,200	74,800	51,850	34,952	29,200	19,890
Number of producing wells	10	17	17	17	16	13
Average yearly production per well	8,220	4,400	3,050	2,056	1,825	1,530
Tract No. 4:						
Total yearly tract production	.....	7,650	13,545	12,625	10,200	7,250
Number of producing wells	.....	1	3	5	5	5
Average yearly production per well	.....	7,650	4,515	2,525	2,040	1,450
Tract No. 5:						
Total yearly tract production	.....	15,060	37,750	14,900	13,100	8,250
Number of producing wells	.....	3	5	5	5	5
Average yearly production per well	.....	5,020	7,550	2,980	2,620	1,650
Tract No. 6:						
Total yearly tract production	.....	16,250	17,400	7,840	7,760	5,880
Number of producing wells	.....	5	8	8	8	7
Average yearly production per well	.....	3,250	2,175	980	970	840
Tract No. 7:						
Total yearly tract production	.....	.....	.....	9,700	8,500	3,650
Number of producing wells	.....	.....	.....	5	5	5
Average yearly production per well	.....	.....	.....	1,940	1,700	730

The records to be combined must first be carefully examined and abnormal irregularities eliminated. The latter include particularly fluctuations preceding the period of symmetrical decline and parts of tract records where there are rapid changes in the number of wells producing or where wells are deepened to other sands, or are unduly affected by water encroachment, cleaning out, or other causes.

Thus the production of the average well of tract No. 5 for 1916 is obviously low, representing production before the period of symmetrical decline for the tract had been reached and should not be used in the construction of the average production-decline curve.

The next step is the plotting of the average yearly production per well of the various tracts. The tract records are used in the order of the amount of the first year's production of the average well, disregarding completely the calendar years in which the production occurred.

On coordinate paper, with the vertical scale representing yearly production in barrels and with the horizontal scale representing years

(see Fig. 14), are plotted the consecutive yearly production records of the average well of the tract having the highest average initial year's production, regardless of the calendar year (tract No. 1, 9,276 barrels).

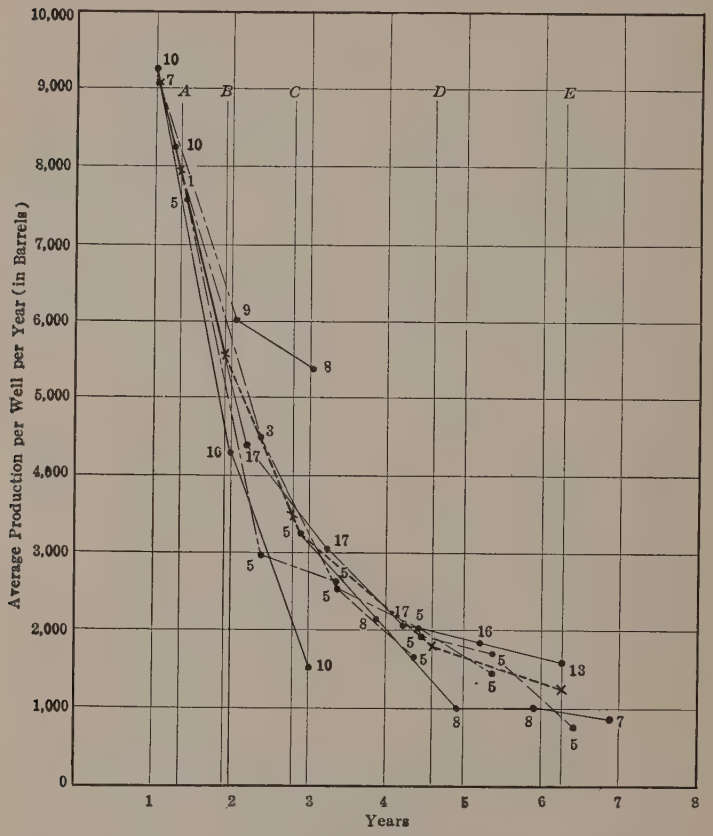

FIG. 14.—Family curve method of constructing an average production-decline curve from production records of separate tracts. (Dashed line, heavier than the broken line represents the average production-decline curve obtained. The figures along the basic curves represent the number of wells involved.) (*From the Manual for the Oil and Gas Industry*).

In order to weight the tracts according to the number of wells producing, the number of wells producing each year is written above the recorded graphic production. The average well of the tract the initial production of which is second highest (tract No. 2) is now plotted, placing its first

year's production (9,076 barrels) on the graph of that tract which is already plotted, and spacing its subsequent yearly production at yearly intervals.

A vertical line *A* is drawn through these two graphs at any convenient place immediately below the point where the record of the next tract will be attached to the average curve. The points of intersection of this vertical line with the two graphs already plotted are now averaged vertically, due allowance being made for the number of wells on each tract. The following computation shows the method of averaging:

The vertical line *A* crosses the graph of the first 10 wells at 7,750 barrels, and the graph of the second tract, which averages 8 wells at this point, at 8,250 barrels.

$10 \times 7{,}750 =$	77,500
$8 \times 8{,}250 =$	66,000
18	143,500

Dividing 143,500 by 18 gives 7,972 as the point where the average production-decline curve for the two tracts will cross line *A*. A dashed line drawn from the point in common of the two graphs, 9,076 to 7,972 barrels, gives the average production-decline curve to the line *A*. On this average line are tied any other graphs whose initial production lies above 7,972 barrels. Tract No. 3, whose initial average yearly production is 8,220, is now tied on.

In Fig. 14 five vertical lines, *A*, *B*, *C*, *D*, and *E*, were used to obtain points on the average curve, thus, consequently, prolonging the curve, which permits the tying on of other wells. When all of the records have been used, the average production-decline curve has been constructed. It is represented by the dashed line in Fig. 14. Irregularities may be smoothed out and the curves extended by passing a curve through the various segments, either on coordinate paper or, better, by transferring the points to logarithmic paper. . . . The resulting average production-decline curve, before it is smoothed out and extended for future years, is as follows: 9,267, 5,320, 3,180, 2,300, 1,650, and 1,250 barrels.

Mathematical Method.—Cutler's mathematical method is equally applicable to the compilation of curves from both individual wells and properties. When based upon the records of tract production the method is as follows:

The accompanying illustration (Table II) is an example of this method, used in constructing the production-decline curve of the average well for seven tracts. Each year's production of the several tracts was divided by the number of wells producing during the year, thus furnishing the successive yearly productions of the average well of each

TABLE II.—ILLUSTRATION OF CUTLER'S METHOD

Tract No.	Column 1		Column 2		Column 3		Column 4		Column 5		Column 6	
	A	B	A	B	A	B	A	B	A	B	A	B
1	84,910 (3)	254,730	52,800 (3)	158,400								
2	83,200 (5)	416,000	53,500 (8)	428,000	40,500 (10)	405,000	32,900 (10)	329,000	24,400 (10)	244,000	17,000 (8)	136,000
3	77,991 (1)	77,991	60,700 (2)	121,400	16,460 (2)	32,920						
4	75,500 (6)	453,000	61,500 (8)	492,000	57,600 (8)	460,800	44,300 (11)	487,300	28,650 (14)	401,100		
5	.....	.....	59,400 (1)	59,400	54,400 (2)	108,800	35,400 (2)	70,800	26,900 (3)	80,700	12,600 (3)	37,800
6	.....	.....	.....	.....	43,300 (5)	216,500	36,600 (5)	183,000	28,060 (5)	140,300	17,380 (5)	86,900
7	.....	.....	.....	.....	47,800 (6)	286,800	37,800 (6)	226,800	31,600 (6)	189,600		
Dividing to obtain Average yearly productions....	(15)	1,201,721	(22)	1,259,200	(33)	1,510,820	(34)	1,296,900	(38)	1,055,700	(16)	260,700
	.....	80,114	.....	57,236	.....	45,782	.....	38,144	.....	27,781	.....	16,293

A—Yearly production of average well of tract. ( )—Number of wells producing in tract. B—Total yearly tract production.

Yearly Production of Average Well Obtained from Above Illustration

Year	Production, barrels
First	80,114
Second	57,236
Third	45,782
Fourth	38,144
Fifth	27,781
Sixth	16,293

tract. The tract whose average well showed the highest initial year's production (84,910 barrels) was used to start the curve as in the graphic method. On conveniently ruled paper (see illustration) the successive yearly productions of the average well of this tract were tabulated in horizontal order in succeeding columns, with the number of producing wells each year in parentheses below, and the total production of the tract for the year to the right of each yearly yield of the average well. For convenience, the main columns were subdivided into two columns, A and B, where A contains the yearly productions of the average well of the tract, and B the total yearly tract production. The tract whose initial year's average well showed the next highest production (83,200 barrels) was then selected and the average production of the initial year was placed in that column (A) which contained the figure nearest this initial production. Thus, 83,200 is nearer 84,910 than 52,800, and, therefore, was placed in column 1. The succeeding years' productions of the average well of this tract were then placed in successive columns with the corresponding yearly tract productions in the B column. This same procedure was followed until all the production figures were utilized, omitting only those for abnormal wells. The figures for average annual production in the A columns were so placed that figures of the same magnitude of the initial year's production of the average well of each tract fell in the same column, and yearly productions of the average well of a particular tract fell in successive columns of the same horizontal line. In the columns to the right may appear the first year's production for a small well and those of the third or fourth year for the larger wells, as the position of the production figures in the columns for any tract does not depend in any way upon the calendar years or the life years of the other tracts, being based entirely upon the size of the initial year's production of the average well of the tract.

To obtain a curve of the average well of the tracts, due consideration must be paid to the number of wells producing each year on each lease. This is called "weighting" the tracts, and is done as follows;

The production figures having been placed in the correct columns, the columns of the total tract production (B) were added and divided by the total number of wells shown in parenthesis (A), the result giving the successive years' productions of the weighted average well for the field. The yearly average well production (A) was used only to place the record in its proper column.

Thus the total for (B) of column 1, the total of the tract productions, was 1,201,721 barrels, which, divided by the sum of the figures in parenthesis (15), gave the weighted average production of the average well of all the tracts during that year, or 80,114. The average of the successive columns furnishes the production of the average well of all the tracts for successive years. These yearly productions may be plotted on coordi-

nate paper to form a production-decline curve in the same manner as that of an individual well. Thus, in the accompanying illustration, the curve will be plotted from the following data:

Year	Production
First	80,114
Second	57,236
Third	45,782
Fourth	38,144
Fifth	27,781
Sixth	16,293

The resulting curve may be smoothed out, eliminating irregularities of curvature and extending the curve downwards to estimate future production. If individual well records are used instead of tract production records, only one figure occurs in each line of the column and no weighting is necessary, the total of each column being divided by the number of figures in the column to obtain the average well's production.

Age Size Law.—Other factors than mere size of a producing well may have a material effect upon the future production of a well, as thickness of sand, spacing, and age of the well. Due to the importance of age in the estimation of future production, Johnson has proposed the Age Size Law stated as follows:[1]

Wells in one pool having the same age and size, counting either from the date the well was drilled or the date the first well was drilled in the pool, will have a production in the following year, which varies but with a central tendency sufficiently reliably determinable that it may be used successfully in the construction of a composite curve.

Special methods have been devised for the development of production-decline curves in conformity to the above law, although the methods previously discussed may be modified to conform with this law by compiling separate curves for groups of wells with approximately the same initial production.

CUMULATIVE PRODUCTION CURVES

In cumulative production curves the total production to date is plotted as one variable and time as the other variable. The production used may be expressed either in barrels or as a percentage of the first year's production. The following table shows (1) the production by years, (2) the cumulative production in barrels, and (3) the cumulative production expressed as a percentage of the first year's production.

[1] Johnson, Roswell H.: Written communication.

Year	Annual production in barrels	Cumulative production in barrels	Cumulative production in per cent of first year's production
1	1,000	1,000	100
2	600	1,600	160
3	400	2,000	200
4	280	2,280	228
5	200	2,480	248
6	150	2,630	263
7	120	2,750	275

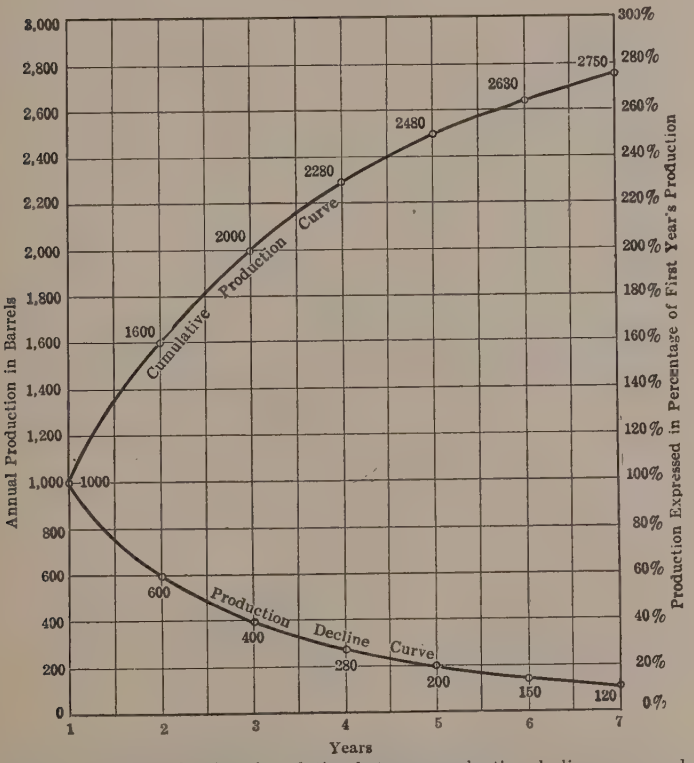

FIG. 15.—Diagram showing the relation between production decline curve and the cumulative production curve.

Figure 15 shows both a production-decline curve and a cumulative production curve based on the table above. The production, both annual and cumulative is given in numbers to the side of the curve. The scale on the left indicates production in barrels; that on the right shows production expressed as a percentage of the first year's production.

COMPARATIVE PRODUCTION CURVES

Curves and tables may be prepared showing the relation between the production of one period and that of another period; the periods compared are ordinarily of equal length, although this need not be the case. For instance, it may be advisable to compare the first 30 days' production with the first year's production, or with total production; or it may be necessary to determine yearly production when given the production for the last day, or the first day, of a yearly period. In general, two methods are used to express these relations. The first method uses a single curve and the second method makes use of an auxiliary curve in connection with the decline curve.

Direct Comparative Curve

In Fig. 16 a single curve is used and direct comparison is made between (1) any year's production, and (2) all subsequent future production. The production upon which this curve is based is given in the following table, together with all the future production subsequent to any given year.

Year	Production for year x	Future production y
First	650	1,855
Second	450	1,405
Third	350	1,055
Fourth	275	780
Fifth	225	555
Sixth	185	370
Seventh	150	220
Eighth	120	100
Ninth	100	0

The value of x for the first year is 650 and the value of y 1,855, which is obtained by adding the production for all following

years, second to ninth inclusive. Similarly, the value for y is found for each subsequent year. In Fig. 16, the values of x are shown by horizontal distances and the values of y by vertical distances.

The curve facilitates interpolation between the points originally plotted. Given a well producing 300 barrels a year, it can readily be determined from the table that its future production will probably be between 1,055 and 780 barrels and it can

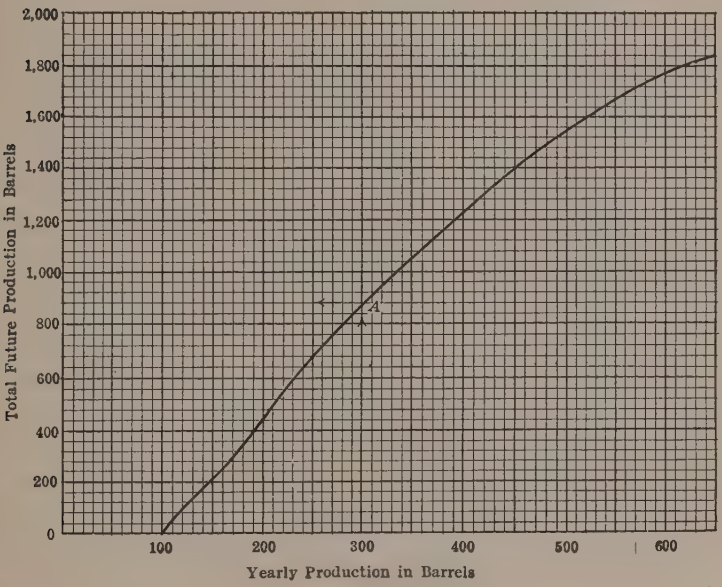

FIG. 16.—Curve showing the relation between the production for one year and total future production.

be rather closely interpolated between these two, but only after considerable mathematical calculation. Referring to the graph, it is only necessary to follow the line indicating 300 barrels yearly production upward to the curved line (point A), and then follow horizontally to the left margin where the future production of 880 barrels can be read directly. The arrows indicate the method of reading the chart. Tables similarly prepared for various fields are found in the "Manual for the Oil and Gas Industry" of the United States Treasury Department. These curves are

quite valuable in the estimation of future reserves, although in themselves they do not give the rate at which the oil is extracted.

Rate-of-production Curve

In the second type of curve an auxiliary curve is prepared to be used in connection with the production-decline curve. Such auxiliary curves have been called rate-of-production curves by Cutler. The following description is taken from the "Manual for the Oil and Gas Industry:"

A daily production-decline curve is called a "rate-of-production curve." Such a curve may be easily formed from any yearly production-decline curve, or from an average production-decline curve of a tract or district.

A rate-of-production curve when used with a yearly production-decline curve shows the normal daily production of a well at the end of its period of production, the position of which is known on the yearly production-decline curve, and conversely it shows where a well, whose normal daily production at the end of a specific period is known, should be placed on the yearly production-decline curve.

Where the production record of a well in a field covers less time than a year, the rate-of-production curve may be used in order to place the well in its correct position on the average yearly production-decline curve and thus may be used to estimate the future production of the well from the average future production curve or tables for the district. The daily production to be used in the application of the rate-of-production curve should be the normal daily production of the well at the time the estimate of future production is made. Care should be taken in determining the present normal daily production to use a daily production which is neither abnormally high nor abnormally low because of some temporary influence.

The use of the rate-of-production curve with an average production-decline curve of a district should always be confined to those wells or tracts having production records so short or irregular that they cannot be used for constructing reliable production-decline curves of unit periods shorter than a year. The use of any average curve is likely to introduce into the estimates of future reserves errors which may be avoided by the use of curves formed from the production records of the wells or tracts under consideration.

As a yearly production-decline curve has a uniform curvature throughout, the average rate of production for a year occurs at some time before the middle of the year. The greater the curvature, the earlier in the year the average daily production occurs.

By dividing the year's curve into a number of equal parts and reading the ordinates of these equal divisions and averaging these ordinates,

the time in any year at which the average daily production occurs may be found by plotting the average ordinate on the curve. The point on the curve where the average ordinate for a year intersects the curve will represent the time of the year at which the average daily production occurs. The time of the average daily production for any year varies chiefly with the percentage of decline of production from the previous year. The following table shows the time in the year at which the average daily production for the year occurs, based upon percentage of decline from the previous year:

Decline of yearly production from previous year, per cent	Time before the end of year when average daily production occurs	
	Per cent of year	Date
0	50	July 1
10	51	June 26
20	52	June 23
30	53	June 19
40	54	June 16
50	55	June 12
60	57	June 4
70	58	June 1
80	60	May 24
90	63	May 14
95	66	May 3
97	69	Apr. 22
99	73	Apr. 7

This table will locate the average daily production for the year at a point where the daily production is within 5 per cent of the correct average daily production for the year.

Construction of Curve.—To construct a rate-of-production curve for any district where an average yearly production-decline curve is available, move the yearly segments of the yearly production-decline curve to the left, to the time given in the above table. This may be done on either coordinate or logarithmic paper.

The same horizontal scale representing time is used for both of these curves. The vertical scale representing barrels per year is divided by 365 in order to provide a production scale for the rate-of-production curve, so that any line representing production in barrels per year will also represent the corresponding production in barrels per day.

Any point on the rate-of-production curve represents the last day's production of the year's production shown on the yearly production-decline curve vertically above.

Use of Curve.—The use of the rate-of-production curve in conjunction with the average yearly production-decline curve is illustrated in Fig. 17, which shows the application of these curves to an average well in the Belridge field, California. A well in this field which produced 22,200

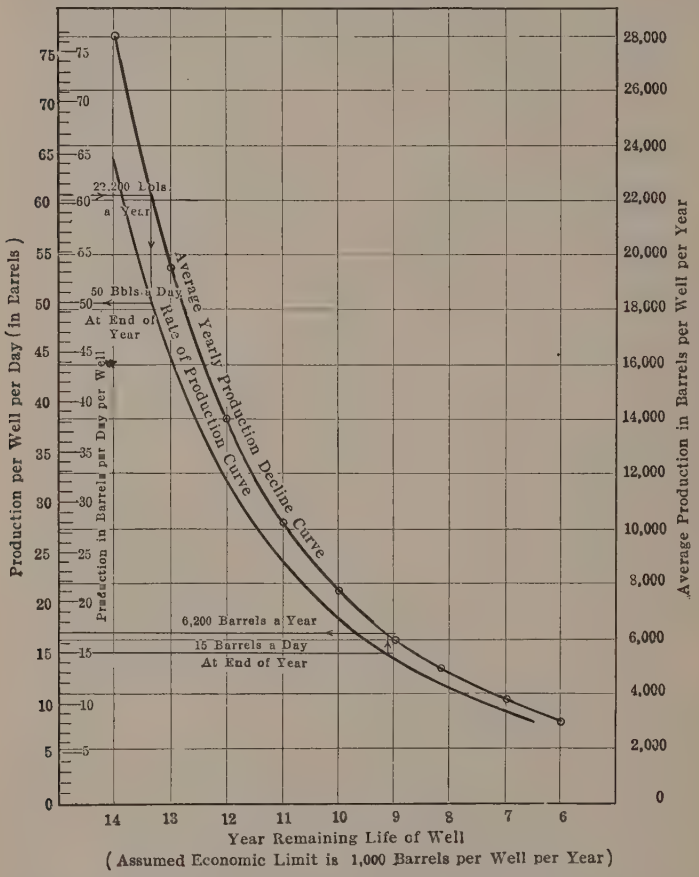

FIG. 17.—Method of using the rate-of-production curve with the production decline curve. In the above illustration, the production decline curve for the Belridge Field, Kern Co., California has been used. (*From the Manual for the Oil and Gas Industry*).

barrels in a given year is estimated to have a daily production at the end of the year of 50 barrels, although the daily average for the year was 60.8 barrels. In Fig. 17, a well in the Belridge field, California, which is producing 15 barrels per day should lie on the average yearly

production-decline curve at 6,200 barrels per year, and its future production is estimated by the yearly production-decline curve . . . to be 21,834 barrels.

A rate-of-production curve can be prepared which will give the monthly instead of the daily production in the auxiliary curve. Production-decline curves are commonly based on a time unit of 1 year; and where wells have been producing for a shorter period, a monthly rate-of-production curve may advisedly be used. A given well may have been producing for only 5 months, and on the basis of the 5 months' production it is necessary to compute the yield for a year.

Two wells, one of which produces 5,000 barrels for the first 5 months and the other that produces 12,000 barrels for the first 12 months, will have the same average daily production for these respective periods. However, at the end of these periods their rates of production will be unequal, as one well has had a longer period of decline. Neither will their future production be the same. A proper solution of the problem is the preparation of the monthly rate-of-production curve by methods similar to those described in the preparation of a daily rate-of-production curve. That position on the monthly rate-of-production curve must be found in which 5 consecutive months give the production of the 5 months of the given well; the production for the next year may then be readily determined.

USE OF PRODUCTION CURVES

Selection of Curve.—The prediction of future production involves the selection of the proper curve and the determination of either the economic limit or the life of the well. When predicting the future production of a well in a given pool, the production curve selected should be compiled from the records of wells in that pool. In the case of an entirely new pool, comparison may be made with the same sand in other pools, although this comparison is likely to be greatly in error, as the yield from a given sand differs from pool to pool. Variations in yield are found in the same pool from place to place and from sand to sand. Consequently, to obtain the most accurate results, curves prepared from records of wells in the same sand and the same part of the pool should be used. A curve prepared from a group of similar wells probably forms the best index of their own future.

Economic Limit.—Wells are abandoned when operating costs equal or exceed the income. This may be due to a decrease in price of oil or an increase of operating costs, but ordinarily it is due to decline in production. "The smallest production per unit of time at which it is profitable to operate a well" has been called the economic limit. This varies greatly from field to field, depending upon operating cost and selling price of oil. The economic limit is exceptionally low in the Appalachian field for both of these reasons, many wells operating at less than one-tenth of a barrel per day. In New York the average daily production was less than one-fifth of a barrel in 1922.[1]

In estimating the future production of a well it is necessary to determine or assume an economic limit. This determination may be based on the production at which other wells are abandoned, or on the cost of operating similar wells and the expected price of oil at date of abandonment. If the operating cost is $1,000 a year and the price of oil $1.25 per barrel, then a production of less than 800 barrels a year, or 2.2 barrels per day, is unprofitable. Quite evidently, wells should be abandoned by the time their daily production has reached this point.

Paraffin Sealing.—Wells may be prematurely abandoned because of paraffin sealing or the encroachment of water. As gas escapes from the oil sand into the well opening, it expands and is chilled. This chilling may cause the condensation of waxy sediment about the opening, clogging the well and decreasing production. The opening may be freed from this wax by steaming, shooting, or by electrical heating appliances. Heat in each of these cases is the active agent. The presence of paraffin on the tubing or sucker rods may be taken as a sufficient warning of danger from this source.

Wells 20 years old were in 1914 being regenerated with great success by an electrical process in the Oil City district of Pennsylvania, the inventor of the process contentedly accepting his payment out of the increased productions following the melting of wax which had previously checked the inflow of oil.[2]

The maintenance of sufficient back pressure on the oil sand will lessen the effect of the expansion of the gas, decreasing chilling and refrigeration of paraffin.

[1] From figures compiled by the U. S. Dept. of Interior.

[2] Thompson, A. Beeby: "Oil Field Development," p. 142.

Water Encroachment.—Many wells have been ruined by water encroachment; others have been saved from a like fate by properly casing off top waters and plugging off bottom waters. Edge water cannot be shut off, but its encroachment in many cases can be retarded; proper pumping may be helpful. Water moves more readily than oil; consequently if a well is pumped too fast the water may break through and shut off the oil. Obviously the remedy lies in pumping slower.

Properties which show the effect of water encroachment or paraffin sealing should be penalized accordingly when determining their value. Sometimes it is possible to compute the rate of the advance of the water and thus estimate the probable date at which the property will be abandoned.

COMPARATIVE RATIOS

Production for a given year may be compared with the total future production, and this comparison expressed in a ratio. Such ratios vary not only from pool to pool but also with the size of the well. When applied to similar wells these ratios may serve as a ready means of making approximations.

In the following table the first two columns are taken from the "Manual for the Oil and Gas Industry." They are for that group of wells of the Glenn sand of the Glenn pool the production of which lies between 4,000 and 8,000 barrels in a given year.

Production per well during a given year in barrels	Estimated average recoverable underground reserves, in barrels	Ratio of estimated future production to production for a given year
8,000	15,000	1.87
7,000	13,500	1.93
6,000	11,800	1.97
5,800	11,535	1.99
5,000	10,150	2.03
4,000	8,400	2 10

From an inspection of the above figures it is seen that the future production is approximately twice the production for the preceding year. Ratios such as the 2 to 1 ratio determined above may readily be memorized and can be applied to other wells meeting the requirements. These ratios should be used only as first approximations.

CHAPTER III

ESTIMATION OF OIL RESERVES: NEW LOCATIONS AND UNDEVELOPED ACREAGE

The estimation of the recoverable reserves of undeveloped acreage and of new locations on partly developed acreage is a much more difficult problem than the prediction of future production of producing wells. A knowledge of the geological structure,[1] character of the oil reservoir,[2] and its relation to the occurrence of petroleum are necessary prerequisites to an understanding of the problem. The productive area must be outlined and the number of wells to be drilled determined.

If a tract is partially developed, knowledge concerning the wells already drilled may serve as a useful guide in estimating the production of new locations their number, and the most economical spacing must be determined and the probable yield from each of them estimated. Acreage must be classified as to its probable productivity, using all available knowledge concerning its geology and drilling history.

CLASSIFICATION OF ACREAGE

Geological Basis

Reservoirs.—Sandstones and sands are the great reservoirs from which petroleum is readily extracted, while shales are usually impervious to the passage of either oil or water. Limestones occupy an intermediate position and may be either impervious, thus forming a barrier to the movement of the oil, or may themselves be the reservoirs. Fissures in shales are the source of oil in the Florence field, Colorado, and also in certain

[1] By "geological structure" is meant the attitude of the rocks of a region, their inclination from horizontal, and general relations of one bed to another. Examples of geological structure are anticlines, synclines, terraces, monoclines, and faults. Diagrams of various types are to be found on the following pages and definitions of these structures in the footnotes.

[2] By an "oil reservoir" is meant an opening or group of openings in a given rock from which oil may be extracted by mechanical means when the overlying strata have been penetrated by a drill hole.

localities in Mexico. The oil from the Kosse field of Texas is reported as probably coming from a similar reservoir.[1] Arnold and Anderson report zones of fractured shale and flint as constituting the source of oil in the Santa Maria district of California.[2] Oil is also obtained from openings in igneous and metamorphic rocks, as in the Thrall field of Texas,[3] in the Furbero district of Mexico,[4] and in the Santa Clara district, California.[5]

Anticlinal Theory.—Within a given reservoir, gas, oil, and water, if present, are arranged on the basis of their specific gravities, gas occupying the higher portion, water the lower, and the oil lying between them. Because of this arrangement oil has popularly come to be associated with anticlines, although it is found in many other types of structure. Success in locating places favorable for the discovery of oil is dependent upon the ability to determine the structure and outline of the reservoir. It is evident that if a porous sand continues but halfway up an anticline, the crest will be dry, and oil or gas, if present, will be found lower structurally (see Fig. 18).

Classification of Oil-bearing Structures.—The following classification of structures is suggestive but not complete:

1. Anticlines (including salt domes).
2. Terraces.
3. Synclines.
4. Sealed monoclines due to:
   (*a*) Lensing of reservoir.
   (*b*) Tightening of reservoir.
   (*c*) Asphalt deposits.
5. Faults.
6. Fissures.
7. Solution cavities.
8. Igneous dikes and plugs.

[1] STROUD, BEN K.: verbal communication.

[2] ARNOLD, RALPH and ANDERSON, ROBERT: "Geology and Oil Resources of the Santa Maria Oil District, Santa Barbara County, California, U. S. Geol. Survey, *Bull.* 322, pp. 73–74, 1907.

[3] UDDEN, J. A. and BYBEE, H. P.: "The Thrall Field," Texas Univ., *Bull.* 66, p. 39, 1916.

[4] DEGOLYER, E.: The Furbero Oil Field, Mexico, Amer. Inst. Min. Eng., *Bull.* 105, pp. 1899–1911, 1915.

[5] ELDRIDGE, G. H.: The Santa Clara Valley Oil District, Southern California, U. S. Geol. Survey, *Bull.* 309, p. 5, 1907.

Anticlines.[1]—The position of oil in an anticline is dependent upon the space occupied by the gas and water present. The oil is under pressure from both above and below, the gas above

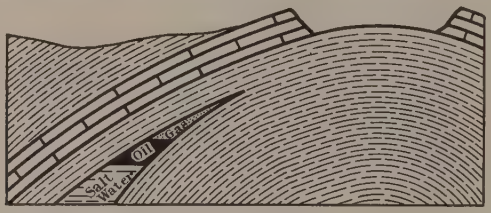

Fig. 18.—Showing the termination of an oil and gas reservoir on the limb of an anticline.

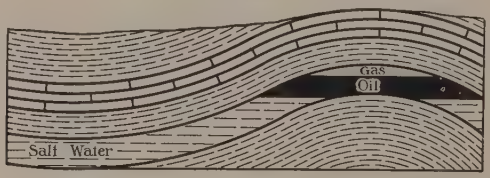

Fig. 19.—Showing the occurrence of oil in the crest of an anticline.

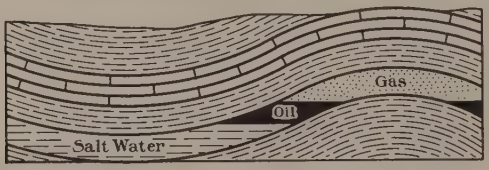

Fig. 20.—Showing the occurrence of oil in the limb of an anticline or syncline.

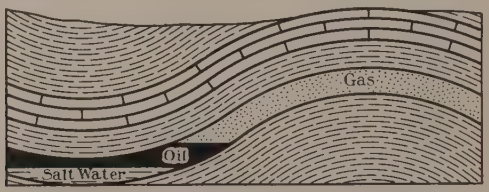

Fig. 21.—Showing the occurrence of oil in a syncline.

the oil exerting a downward pressure, while the hydrostatic force of water below exerts an upward pressure. Figure 19

[1] An anticline is ridge or dome-shaped; it is a fold in stratified rocks in which the central portion is highest, the rocks dipping away on either side (see Fig. 18).

shows oil near the crest of an anticline where the volume occupied by the gas is small. Figure 20 shows oil further down on the limbs of an anticline, the entire crest being occupied by gas. Figure 21 shows the occurrence of oil in a syncline.[1] The amount of water in this case is small. The occurrence of oil in synclines is reported in the Appalachian field, south of Pittsburgh, Pennsylvania. The relations frequently are not as simple as shown.

Structure should be considered in all three dimensions rather than in cross-section. On this basis several types of anticlines are existent. In outline they may be circular or elongated. In elongated anticlines the axis may be nearly horizontal or it may be inclined. Domes are a special form of anticline in which the strata dip away from a central point. The salt domes of the Gulf province are of this type but differ from typical anticlines by having a core of salt.

Many interesting relations may be noted concerning the occurrence of oil in anticlines. Oil underlies a larger area and occurs further down the dip on the west side in the anticlines of the Osage field. In other cases oil may occur in one limb of an anticline and be absent in the other. In the Big Horn Basin those anticlines which lie lower structurally are the most prolific.

The following discussion concerning the relative value of anticlines is by Heald:[2]

> In estimating the value of an anticline for oil and gas production one of the most important considerations is the gathering ground. The oil and gas do not originate in the crest of the anticline where the accumulation is most generally found, or even in its flanks, unless the anticline is a very large one. They must come from a very considerable area, particularly if the oil sands are comparatively thin, as they are in many oil fields in northeastern Oklahoma. It is believed that the oil and gas were originally disseminated through the rocks in minute quantities, and that all these scattered drops of oil and bubbles of gas have moved through the water-saturated rocks until they reached a point which for some reason retarded their progress. The factors that caused this movement are not thoroughly understood, but it is known that the direction of the movement was up the dip of the rocks, and therefore

[1] A syncline is basin or trough-shaped; it is a fold in stratified rocks in which the central portion is lowest, the rocks dipping inward from either side.

[2] Heald, K. C.: "Geological Structure of the Northwestern Part of the Pawhuska Quadrangle," U. S. Geol. Survey, *Bull.* 691–C, pp. 96–99.

toward the surface of the ground—that is, oil tends to rise, and conversely, it apparently has difficulty in sinking. Accordingly, when it reaches a point such as the crest of an anticline, where it would have to go downward to progress farther, it must stop. It may be safely assumed that the oil will travel straight up the dip of the rocks if the rocks are continuously porous. The gathering ground of any anticline is, then, the ground from which the oil, following this tendency, would ultimately reach the crest of the anticline.

A second factor is the ability of the anticline or other minor structural feature to arrest the progress of the oil and gas. This depends to a large degree upon the "closure" of the fold. Many anticlines do not dip away from some central point on all sides, and it is obvious that there is at least one place on such a fold where the oil and gas may move on through the fold without being arrested by its inability to move downward. It has been found, however, that a very considerable change of dip may be almost as effective in stopping the progress of the migrating oil and gas as an actual reversal of dip, and that these minerals have great difficulty in moving past points where the rocks are approximately level. If, then, the axis of an anticline does not plunge steeply, there is a good chance that the fold will retain some oil, even though there is one direction toward which the beds in it do not dip.

A third factor is the capacity of the anticline. The writer believes that in a small minor fold on a monocline the chances of oil accumulation are also small, although the probability of gas being present is good. This may be explained by the fact that gas is more volatile than oil and will therefore pass more rapidly through the rocks. When the oil and gas begin to migrate, the gas will precede the oil and will fill to the capacity any minor domes and wrinkles. When the slower moving oil reaches these small folds there is no room for it in the folds, and it accordingly crowds around their edges and passes on.

A fourth factor is the shape of the anticline. A very large flat anticline with a large gathering ground might supply many small wells; a similar anticline with a relatively small gathering ground might show only "shows" of oil, because the oil might be disseminated through the flat beds that form the crest. Oil occupying an anticline rising sharply to a crest or to a central point would tend to be concentrated at that crest or central point, and wells on such an anticline should have a larger daily yield and would yield more oil during their lifetime.

A fifth factor is the development work which has been done. Proof of the presence of oil is always better than theoretical arguments. A small anticline with an oil well on it is a better property than a much more promising-looking fold that has not been tested. There are so many factors any one of which may make structural work on the surface of no avail that there can be no "sure thing" in untested territory,

and even beds showing the most evident anticlinal structure may prove dry of oil. . . .

In choosing a locality for drilling on an untested anticline, the shape of the fold is the first consideration. If the fold is a dome, the very top is the most favorable point for testing; if it is an elongated anticline, some point along or near the axis should be chosen.

Terraces.[1]—Oil frequently is found in terraces. In the migration of oil upward along an inclined surface under the force of gravity, the effectiveness of this force is lost if the strata become horizontal and the oil migrates no further, as illustrated

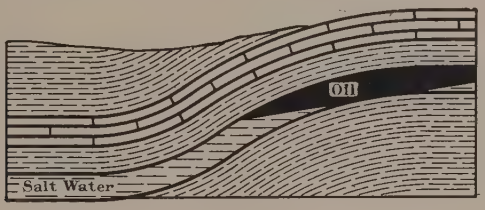

FIG. 22.—Showing the occurrence of oil in a terrace.

in Fig. 22. In selecting a location for drilling on an untested terrace, the place of greatest change in the inclination of the beds should be chosen.

Monoclines.[2]—The occurrence of oil in monoclines may be due to the termination of the reservoir by the lensing out of the sand, or because of decrease in its porosity. These conditions are shown in Figs. 23, 24 and 25. The first two cases represent hypothetical conditions, but can be duplicated in principle in many places; the last figure is of a known deposit.

An oil reservoir may be terminated along the planes of stratification through the decrease in the size of the openings, which may be due to greater cementation, the occurrence of finer particles with consequently finer openings, or to a more compact arrangement. Sands deposited along stream beds may grade rapidly into clays or may terminate abruptly against clay banks, when consolidated, the sand beds formed would be in long narrow

[1] A terrace is a structure in stratified rocks in which a sloping bed becomes horizontal or nearly so when followed upward, as shown in Fig. 22.

[2] A monocline is a structure in which stratified rocks dip in one direction without appreciable change in either the direction or the amount of dip (see Figs. 23 and 24).

belts. The Hogshooter pool[1] is thought to be formed under such conditions. A similar origin may be the explanation of some of the "shoestring" pools.

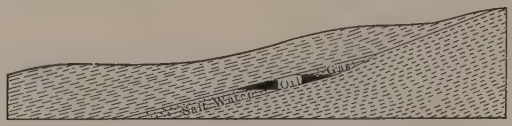

FIG. 23.—Sketch showing reservoir sealed by impervious rocks overlying and underlying the reservoir rock and joining above the reservoir. (*After Emmons*).

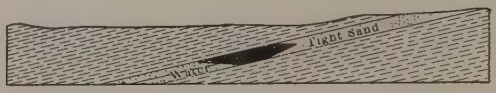

FIG. 24.—Sketch showing reservoir sealed by tight sand. Black is oil and gas. (*After Emmons*).

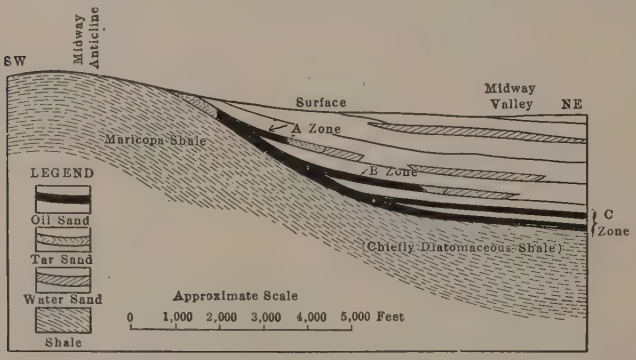

FIG. 25.—Diagram showing relations of productive oil zones in the vicinity of Fellows, Midway-Sunset district, California. (*After Pack*).

Faults.[2]—Faults may or may not act as barriers to prevent the further migration of oil. In Fig. 26, *B* illustrates the condition in which migration is possible across the fault line; in conditions shown at *A* there can be no migration across the fault from one sand into another, and thus, an oil reservoir is formed.

[1] BERGER, WALTER R.: "The Extent and Interpretation of the Hogshooter Gas Field," *Bull.* Am. Assn. of Petroleum Geol., *vol.* 3, pp. 212–216.

[2] A fault is "a break in the continuity of a body of rock attended by a movement on one side or the other of the break so that what were once parts of one continuous rock stratum or vein are now separated."

FAY, ALBERT H.: "A Glossary of the Mining and Mineral Industry," U. S. Bur. Mines, *Bull.* 95.

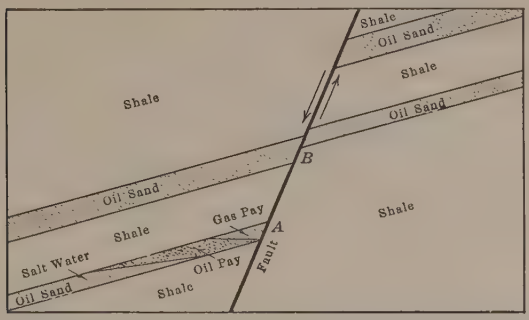

FIG. 26.—Diagrammatic cross-section showing (at *A*) an accumulation of oil and gas caused by a fault and (at *B*) a possible condition under which a fault may not seal a reservoir. (*After Fath*).

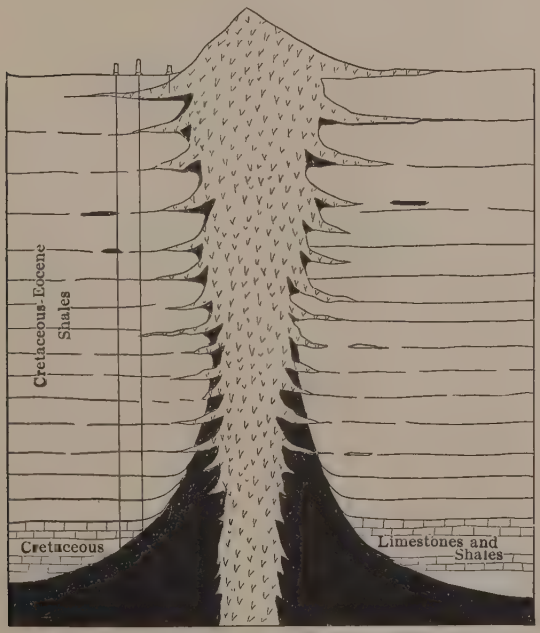

FIG. 27.—Hypothetical section, according to Garfias, illustrating basalt intruding the oil series of Mexico and reaching the surface. Black represents the places that are favorable for oil accumulation. The plug is larger near the surface where expansion is easier, owing to lighter load.

Fissures[1] and Solution Cavities.—Occasionally oil is found in fissures and solution cavities. The presence of oil in fissures in shale has already been noted. Solution cavities occur in limestones which have been subjected to the influence of surface water, and would, consequently, be confined to beds subject to erosion and hence underlying an unconformity. Both cavities and fissures present unusual problems in estimating oil reserves.

Igneous Dikes[2] and Plugs.[3]—Oil deposits may be associated with areas of igneous activity. Igneous dikes may serve as dams, thus preventing the further migration of oil and forming oil pools. In certain parts of Mexico, oil deposits occur about volcanic plugs, as shown in Fig. 27. The intrusion of plugs into sedimentary rocks in some places has arched the beds, and the anticlines so formed may act as oil reservoirs.

The foregoing classification is suggestive of the numerous modes of the occurrence of petroleum; each of these types can be studied profitably in considerable detail.

Methods of Classification

Use of Geological Maps.—A geological map and report should be prepared showing the structural conditions under which the oil occurs, the location of the gas, oil, and salt water wells, the dry holes and the boundaries of the probable productive area. Figure 28 is a structural contour map showing the results of drilling, and outlining the oil, gas, and non-productive areas. The solid lines are structural contours based on the top of a coal bed; a given structural contour line represents points on the top of this bed, all of which have the same elevation above sea level. The innermost contour line indicates points all of which are 1,000 feet above sea level and as one proceeds outward the contour lines represent points 900, 800, and 700 feet above sea level, respectively. The structure shown is evidently that of an elongated anticline. It will be noticed that both oil and gas wells occur further down structurally on the north side of the anticline than on the south side. Consequently the boundary lines

[1] The term "fissure" is here used to denote a crack, break, or fracture in rocks whether extensive or of only minor size.

[2] A dike is a thin body of igneous rock with considerable extent in two directions; it is either vertical or highly inclined.

[3] A volcanic plug is a columnar-shaped body of igneous rock, which has solidified in a chimney-like passage.

between the oil, gas, and non-productive zones do not exactly coincide with the contour lines.

A thorough discussion of the problems involved and of the methods of preparing such reports and maps is impossible at this point, but they have been treated in detail by other authors. The foregoing map indicates only two classifications of oil land—probable or proven oil land and worthless oil land. Frequently definite lines cannot be drawn and further classification is required.

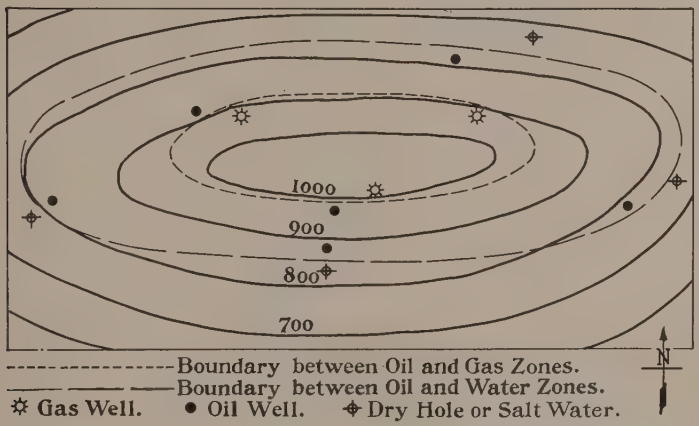

FIG. 28.—A structural contour map. The solid lines are structural contours. Dashed line is the boundary between the oil area and the salt water and dry hole area. Dotted line is the boundary between the oil area and the gas area.

Beal's Classification.—Beal[1] has classified oil lands into;

1. Proved acreage.
2. Probable oil land.
3. Prospective oil land.
4. Commercially non-productive oil land.

Proved acreage should include that in which drilling involves practically no risk. The following definition is proposed, which has been modified from that given by R. P. McLaughlin. "Proved oil land is that which has been shown, by finished wells supplemented by geologic

[1] BEAL, CARL H.: "Factors in Valuation of Oil Properties," Am. Inst. Min. Eng., *Bull.* 153.

data, to be such that other wells drilled thereon are practically certain to be commercial producers."

Probable oil land includes those areas generally adjacent to producing oil and gas wells where existence of oil is not proved, but where geologic evidence indicates a good chance of obtaining oil in commercial quantities.

Prospective oil land includes those areas usually not adjacent to producing oil and gas wells, where the existence of oil is not proved, but where geologic data justifies drilling a test well. Land in this class is distinguished from the probable oil land by the greater uncertainty of obtaining oil, owing, usually, to its location some distance from producing oil and gas wells.

Commercially non-productive oil land is that on which commercially productive wells cannot be drilled at present. The existence of oil under the areas of this class may be proved, probable, or prospective.

Quantitative Classification.—Valuation is a quantitative problem and the foregoing classifications are qualitative; hence, while acceptable for preliminary examination, more exact classification is required. Is proven land to be considered 100 per cent proven and no allowance to be made for dry holes? What are the probabilities of obtaining production on probable oil land? Is it 2 to 1, or 1 to 1, or 1 to 2? Likewise, how many holes must be drilled in order to obtain one producing well on prospective acreage? These are difficult questions to answer but that is no reason that they be ignored. In valuing a property for purchase, certain definite assumptions will have to be made concerning the likelihood of obtaining production. These assumptions should be conservative but definite, because the valuation must be definite in order to compare with the purchase price. For this reason undeveloped acreage must be thoroughly analyzed and compared with developed or condemned acreage under similar conditions in order to answer the question: "What are the chances of obtaining production on this particular area?" The answer should be stated in a percentage form or as a definite ratio.

NEW LOCATIONS

Number of Locations

The proper classification of acreage is but the first step in determining the number of new locations to be drilled. That spacing of wells must be determined which will yield the greatest

profit, and, when determined, the number of new locations to be drilled can readily be computed. Until the most profitable spacing has been attained, a tract must be considered only partially developed, and as this spacing is dependent upon a number of factors, including the price of oil, it is evident that a tract can be considered partially or fully developed only for a given set of conditions. The increased price of Pennsylvania crude in the spring of 1920, when the price rose to $6.10 a barrel, caused renewed drilling activity around Oil City, Pennsylvania. This land had long been considered fully developed. Likewise, a sudden slump in the price of oil may cause a tract previously considered only partially developed to be classed as fully developed.

TABLE III.—VARIATION IN PRODUCTION PER ACRE WITH DIFFERENT SPACING OF WELLS IN THE BARTLESVILLE FIELD, OKLAHOMA[1]
(*After Beal and Lewis*)

A	B	C	D	E	F	G
Daily production per well, first year, barrels	Average acreage per well	Average daily production per well, first year, barrels	Average thickness of sand, feet	Average age of production, years	Average total production of oil per acre,[2] barrels	Number of properties used in obtaining average
11–20	2–4	14	26	8	2,930	28
	5	14	27	9	2,550	20
	6–8	15	26	9	2,090	10
21–30	3–4	24	27	9	6,500	5
	5	26	30	9	5,650	7
	6–8	25	28	9	3,000	4

[1] The sand was identical under each property and the depths differed little.

[2] These total production figures, for all practical purposes, may be taken as representing ultimate production, for the production of most of the properties had declined to 1 or 2 barrels per well daily.

Factors Determining Spacing.—Many factors enter into the determination of the most profitable spacing of wells. If they are spaced too closely, the cost of drilling and operation will reduce the profit; if too widely spaced, the profit will be reduced because of insufficient recovery of oil. Table III shows the recovery of oil for different spacings. The price of oil affects

TABLE IV.—NET PROFIT DERIVED FROM EACH ACRE[1] OF OIL LAND ON SEVERAL PROPERTIES IN THE BARTLESVILLE FIELD, OKLAHOMA, WITH DIFFERENT ACREAGES PER WELL, VARIABLE PRICE OF OIL, AND WELLS PRODUCING 11 to 20 BARRELS DAILY THE FIRST YEAR

						Price of oil, 60 cents per barrel		Price of oil, $1.10 per barrel		Price of oil, $2.10 per barrel	
A	B	C	D	E	F	G	H	I	J	K	L
Average acreage per well	Average production of oil per acre, barrels	Number of properties used in obtaining average	Drilling cost per well[2]	Number of wells per acre	Drilling cost per acre[3]	Total income per acre after deducting production cost of 10 cents per barrel	Net income from each acre[4]	Total income per acre after deducting cost of 10 cents per barrel	Net income from each acre	Total income per acre after deducting production cost of 10 cents per barrel	Net income from each acre
2–4	2,930	28	$5,000	0.33[5]	$1,650	$1,465	−$185	$2,930	$1,280	$5,860	$4,210
5	2,550	20	5,000	0.20	1,000	1,275	275	2,550	1,550	5,100	4,100
6–8	2,090	10	5,000	0.14[6]	700	1,045	345	2,090	1,390	4,180	3,480

[1] Land value and mineral rights excluded for sake of simplicity.
[2] Assumed to be approximately the same because wells on all properties were about the same depth.
[3] Obtained by multiplying amounts in column D from respective amounts in column E.
[4] Obtained by subtracting amounts in column F from respective amounts in column G.
[5] Assuming 3 acres per well.
[6] Assuming 7 acres per well.

the most profitable spacing; when low prices prevail wide spacing is most profitable. In Table IV, the value of the oil produced for different spacings and different prices of oil is compared with drilling cost, and profit and loss computed for each set of conditions. The most profitable drainage area for each well is 6 to 8 acres when oil is selling at 60 cents per barrel, 5 acres when oil is selling at $1.10, and 2 to 4 acres when oil sells at $2.10. If oil sells at 60 cents a barrel, a spacing of 2 to 4 acres to the well would cause a loss of $185 an acre.

Well-spacing Charts.—Well-spacing charts may be prepared showing the most economical spacing under a given set of conditions. To be of the greatest value, separate charts should be prepared for each distinct pool and allowance made for differences in total yield and effective drainage areas, which not only vary from pool to pool but also within a given pool. Furthermore, these charts may soon become obsolete, either through changes in price of oil or drilling costs, unless provision is made for variation in these factors. Figure 29 is a well-spacing chart for average conditions prevailing in the Mid-Continent field, October, 1922.

> The chart shown . . . indicates the average cost of a well from 1,000 to 4,000 feet. At the top is shown the depth of the well in feet, the curved line below indicating the cost per foot at various depths. The middle section shows the well cost at various depths, the additional costs to be added for the proportion of the general surface equipment of the property. The lower section shows the proportionate spacing, consistent with the depth and cost of well. For example, the chart shows that a 2,500-foot well costs $8.88 per foot, or $22,000, to which $9,000 should be added as its proportion of the cost of the surface equipment. The economical spacing of the wells is 1 to 7 acres, or 550 feet apart.[1]

Unless the operator owns a large tract of land, or makes an agreement with operators of adjacent properties, the determination of the most profitable spacing may be of but little value. Assuming that the average lease is 40 acres, it may be necessary to drill one well in each corner of the tract as an offset to wells in adjacent tracts. Each well will thus be limited to a drainage area of 10 acres, although 20 acres may be a more economical spacing. These conditions are aggravated in town lot development, where the spacing of wells is often ridiculously close.

[1] Cox, Thomas: "Relation of Bonuses and Costs to Present-day Prices of Crude and its Products," *Trans.* Am. Inst. Min. & Met. Eng., No. 1207–P.

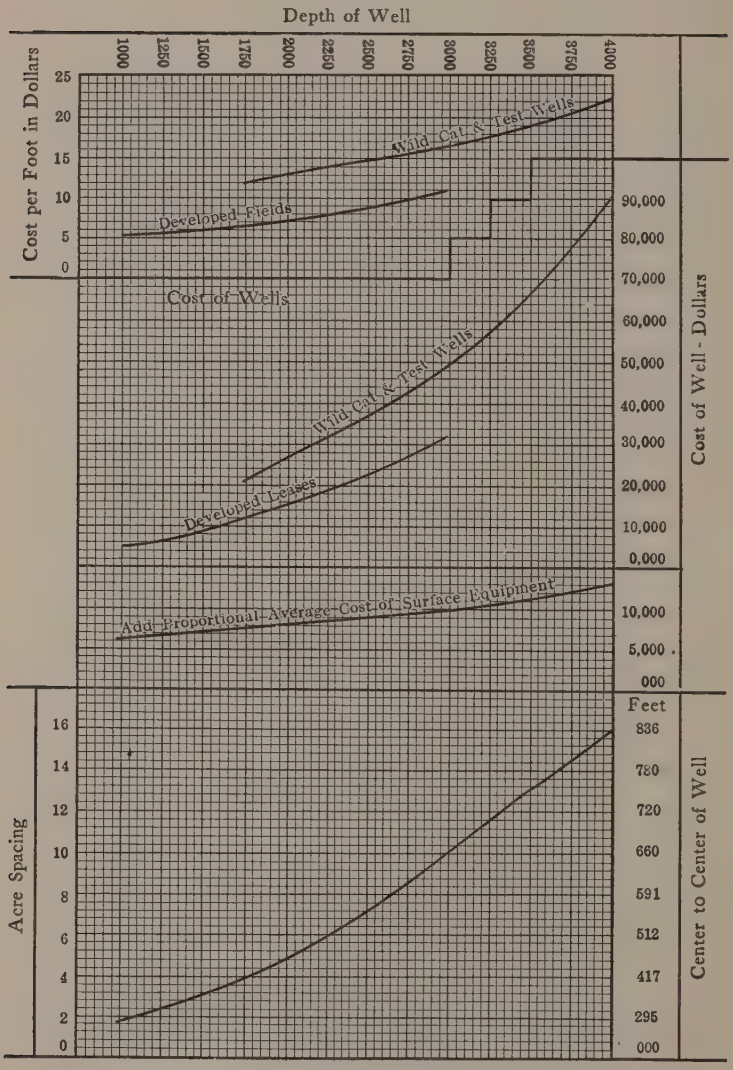

FIG. 29.—Well spacing chart. (*After Cox*).

Drilling Program

After determining the number of wells to be drilled it is necessary to calculate the rate at which drilling is to be pursued. If financial resources are limited, a rapid drilling program may be impossible because of the great initial cost involved prior to the realization of any return on the investment. If a constant supply of petroleum is desired to fulfil a contract with a refinery or to supply the company's own refineries, an increasing rate of development may be advisable to offset the decline in initial production and the effect of interference. On the other hand, if all of the oil is readily marketable, if financial resources are ample, and if prices of crude oil are high, a rapid drilling program would undoubtedly return the investment with interest in the briefest space of time; less deferment is thus involved and less discount need be considered when reducing future income to present worth.

The determination of the drilling program is not entirely under the control of the operator; usually offset wells must be drilled to protect his own acreage. Small tracts of irregular shape are affected to a greater degree by activity of the neighbors than are large tracts of regular shape with their larger number of inside locations, as the drilling of these locations is entirely under the control of the operator. The operator who drills the first well obtains a greater portion of the flush production, utilizes to a greater extent the gas pressure, and in the case of unconsolidated sands takes advantage of such drainage channels as may be established, thus diverting to his own wells some of the oil which otherwise would find an outlet through other wells. In estimating the value of a tract an operator must consider whether his neighbor will dictate his drilling program or whether he can determine it for himself; in the former case he must compare his financial resources with the cost of drilling such offsets as may be required.

Production of New Wells

Steps Involved.—Three steps are commonly involved in the estimation of oil production from new wells:

1. Estimation of initial productions.
2. Conversion of initial production into production for such time period as may be used in the production curve.
3. Use of some form of the production curve.

The first step presents a new problem, the second step is solved by means of one of the comparative curves, and the third step is the same as the estimation of reserves on producing wells. The following example illustrates the steps involved: The pro-

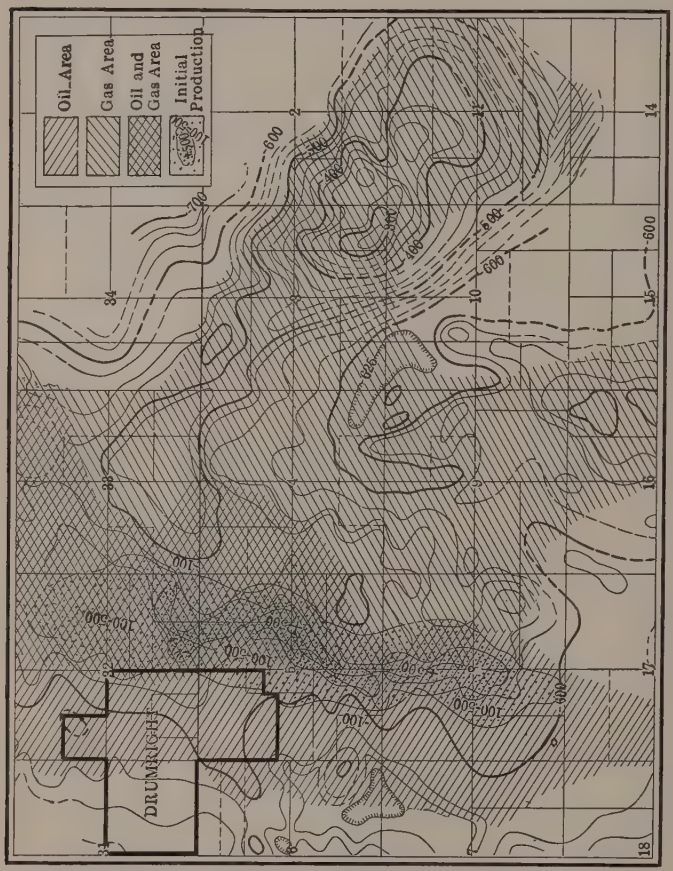

FIG. 30.—The Drumright dome, Cushing field, Oklahoma, showing location of wells of highest initial production. The solid lines are structural contours. (*After Beale*).

duction for the first 24 hours is estimated to be 1,000 barrels. By use of a comparative curve it is estimated that such a well will produce 50,000 barrels the first year. The future yearly production is determined by consulting the production-decline curve for the pool.

Where production is obtained from consolidated sandstones, the prediction of the initial production of new wells may be based upon one of two assumptions; either interference between producing wells may be considered the essential factor governing the initial productions, or variation in structural and sand conditions may be considered the governing factor. The former

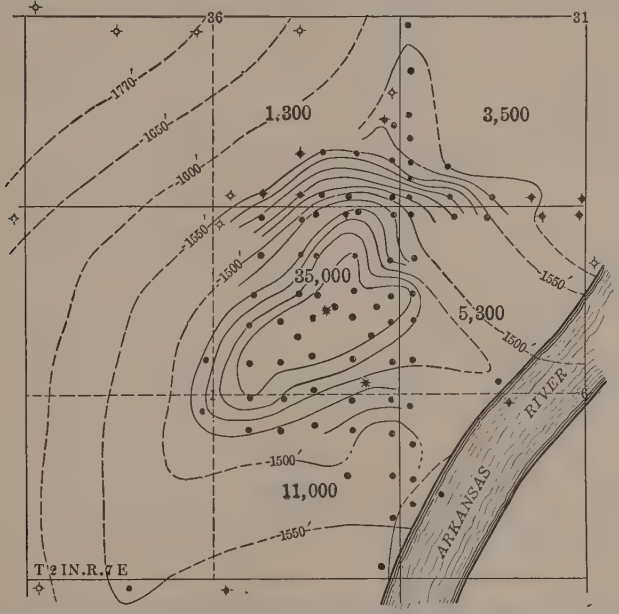

FIG. 31.—Sketch showing the relation between total production per acre (in barrels) and geological structure in the Boston pool, Oklahoma. Figures printed in heavy type indicate the yield per acre in barrels. Both the dotted and solid lines are structural contours. (*After Beale*).

assumption postulates a declining initial production; the latter postulates an initial production varying from place to place but without any uniform variations with respect to time. In unconsolidated sands allowance must be made for a third factor, the influence of drainage channels.

Geological Influence.—Frequently wells of greatest initial production are all in one area or zone. Lines of equal initial production can be drawn so that all initial productions on one side of the line are higher than those on the other. The process of drawing these lines is much the same as drawing contour lines

from a series of known elevations. A comparison of these maps with structural contour maps often show certain relations which aid in the prediction of initial production. Where gas occupies the crest of the anticline, the greatest initial productions and greatest oil recoveries per acre will not occur at the highest point of the anticline, but a short distance down the slope, where great gas pressure and oil content unite in producing large yields, as shown in Fig. 30. The dots indicate oil wells and the numbers indicate initial production in barrels for the first 24 hours.

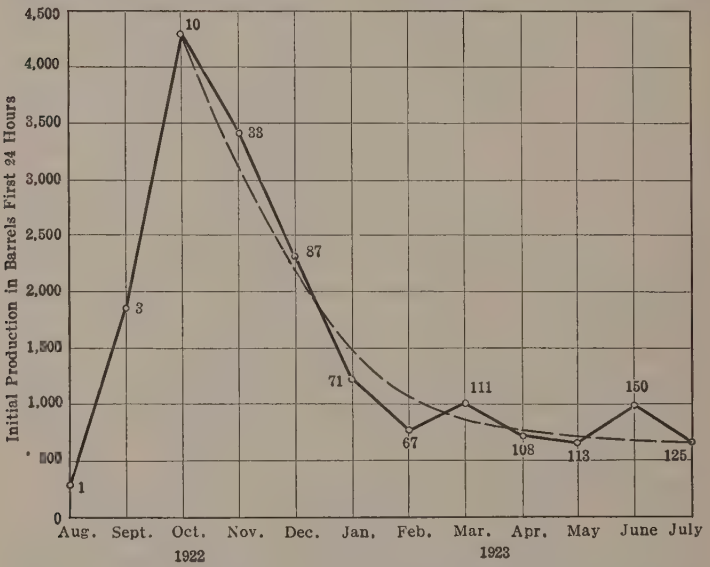

FIG. 32.—Diagram showing the decline in initial production (first 24 hours) of the Smackover Field, Arkansas, for the first year. The numbers indicate the number of new wells added each month, it is upon the average of these wells that the curve is based. (*Data from the Shreveport Times*).

The influence of structure upon total recovery can be seen from Fig. 31, which is a map of the Boston pool, Oklahoma. Gas is not so abundant on the crest of the anticline as to interfere with oil production, but acts as a driving force in the expelling of petroleum, resulting in the maximum production at the top of the dome.

Effect of Interference.—Due to interference, the initial production of new wells may be but slightly in excess of the average

of the wells already producing, and the output of these new wells may soon be reduced to the average production of the older wells. The prediction of initial production of prospective wells may then be based upon the production decline curve of the wells already drilled.

Curves showing the decline in initial productions may be used where more accurate determinations are required. Figure 32 shows the average initial production for the first 24 hours of wells completed each month for the first year of the Smackover

FIG. 33.—Showing how a well may establish drainage lines and draw oil from subsequent wells. (*After Hager*).

field, Arkansas. The initial production the first few months increased greatly due to the location of more productive areas; but once this area was located, initial production decreased, owing largely to the effect of interference between wells. Only a few irregularities will be noted.

Influence of Drainage Channels.—The initial production of wells obtaining oil from unconsolidated sands may be influenced by the establishment of drainage channels. The offsetting well to a gusher is frequently a great disappointment to its owners—it does not live up to the expectations placed upon it by the yield of its phenomenal neighbor. This may be attributed to the establishment of drainage channels, which, as long as

production is maintained, prevent the ready flow of oil into neighboring wells. This condition is illustrated in Fig. 33, after Hager.[1] The first well drilled (No. 1 in the figure) established drainage channels in all directions so that wells drilled later (wells 2, 3, 4, and 5 in the figure) produced but little oil. According to Huntley,[2] in the Glenn pool, where the sands are loose, due probably to shattering by nitroglycerin, it is necessary to pump wells 24 hours a day, 365 days a year. If operations on a given well were suspended, neighboring wells could extend their drainage channels, breaking down the drainage system of the first well so effectively that, when reopened, its production would be greatly diminished.

Thompson[3] reports similar establishment of drainage channels in the Baku oil fields, where a new well within 50 feet of an old one, drilled into the same sand and at the identical depth, failed to produce more than a fraction of the then present yield of the old well. He cites the following example:

> An illustration of this feature was vividly impressed on the author's notice when opening up an old well that had for many years been abandoned as unproductive, with a remarkable result that a production of 40 tons (300 barrels) daily was obtained, and this in a district where the maximum yields of new wells sunk away from the old wells was 15 tons (130 barrels) daily. Long standing had led to the infiltration of oil into the area of low density formed by the original extraction of much sand, and the same circumstance, together with the presence of oil feeders, rendered its removal easy. In the case of a new well in such an exhausted and low producing district, there would not have been sufficient gas left to expel the oil from the sands, and the exudation from compact undisturbed sands would have been very slow indeed without the aid of gas.

UNDRILLED ACREAGE

The value of undeveloped acreage depends primarily upon geological conditions; estimates of oil reserves are based upon a knowledge of the oil sand or sands. Two methods in general may be employed: (1) the saturation method, (2) the acre-

[1] HAGER, DORSEY: "Geological Factors in Oil Production," Min. and Sci. Press, vol. 103, p. 740, Dec. 9, 1911.

[2] HUNTLEY, L. G.: "Possible Causes of the Decline of Oil Wells and Suggested Methods for Prolonging Yields," U. S. Bur. Mines, *Technical Paper* 51, p. 23.

[3] THOMPSON, A. BEEBY: "Oil Field Development," p. 136, 1916

yield method. While these methods are particularly applicable in estimating oil reserves on undrilled tracts, they are not without value in estimating the reserves on other types of properties. Certain factors already discussed relative to the estimation of reserves are also applicable to undeveloped tracts.

Saturation Method

The saturation method, described by Washburne, consists in estimating (1) the amount of sand, (2) the volume of pore space, (3) the percentage of saturation, and (4) the percentage of recovery. The formula for determining the recoverable reserves may be expressed as follows:

$$R = 7{,}758\, A \times t \times p \times s \times r$$

where R is the recoverable oil in barrels.
A is the area of the tract from which oil is drawn, in acres.
t is the average thickness of oil sand, in feet.
p is the percentage of porosity of the oil sand.
s is the percentage of the saturation of the oil sand.
r is the percentage of recovery of the total oil contents.

Amount of Sand.—Each of the above factors is subject to error. Not even the area from which the oil is extracted can always be ascertained accurately, as oil may be drawn from adjacent tracts, or neighboring wells may partially drain the tract under consideration.

Errors are frequently involved in reporting the thickness of the pay sand. Owing to differences of opinion among drillers as to what actually constitutes pay sand, their reports differ greatly. The most common error is that of exaggeration. To obtain accurate data, a core of the sand should be taken for examination. Even when accurate data are secured for a given area, errors may arise if these data are applied to another area, especially if the sand from which the data are compiled is "spotted" or varies irregularly.

Porosity.[1]—Oil is found in the pore spaces of sandstones. The amount of pore space is dependent upon the shape of the grains, the uniformity of their size, their arrangement, and the degree of cementation; the pore space between spheres of uniform size which are packed in the most compact manner is 25.95 per cent by volume (see Figs. 34 and 35). Porosity is indepen-

FIG. 34.—Spheres packed in the most compact manner possible. The face angles are 60° and 120°. (*After Slichter*).

dent of the size of the grains, although the size of each opening varies directly with the size of the grains, other factors remaining unchanged. The pore space may be less if the sand grains are of different sizes than if they were uniform, as the smaller grains

[1] Porosity may be defined as "the volume of pore space expressed as a percentage of the total volume of the rock mass." (FAY, A. H.: "A Glossary of the Mining and Mineral Industry," U. S. Bur. Mines, *Bull.* 95.)

A porosity of 50 per cent means that the volume of the pores between the rock particles is equal to the volume occupied by the rock particles themselves.

may fit between the larger ones. This factor is of considerable importance in some California fields. If the sand grains are irregular, the porosity may be greater or less than that with perfect spheres. The amount of porosity also depends upon the arrangement of the grains and the manner in which they are fitted together. Mica flakes permit of a much denser arrangement than do spheres, but if they are arranged irregularly, without any tendency to lie in a compact manner, their pore space will be the greater. Porosity is frequently greatly reduced by

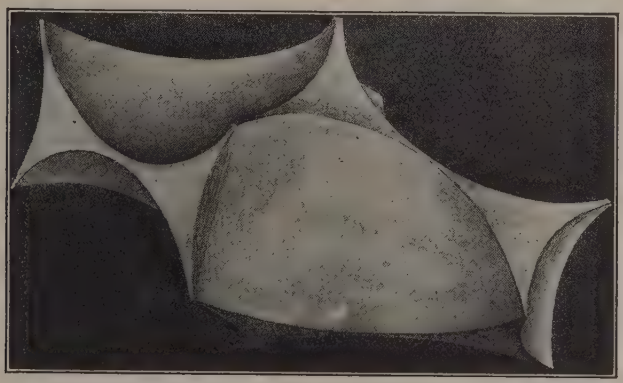

FIG. 35.—Cast showing pore space in a mass of spheres packed in the most compact manner possible. (*After Slichter*).

cementation; for this reason sands are more porous than sandstones, and sandstones more porous than quartzite.

Openings in limestones are usually formed either by solution or dolomitization. When a fairly pure limestone is changed to dolomite without addition of carbon dioxide, a shrinkage of approximately 12 per cent occurs. Limestones are barren where neither solution nor dolomitization have occurred, although elsewhere, where these processes have been effective, the limestone carries oil, as is the case with the Trenton limestone of the Lima-Indiana field.

The porosity of certain sandstones producing oil and gas is given in the following table:

TABLE V

Field and sand	No. of samples	Min.	Max.	Av.
Bradford sand, Custer City, Pa.[1]	1	....	....	17.8
Big Injun, Ohio[1]	3	11.3	13.1	12.2
Keener sand, Ohio[1]	5	11.3	18.4	14.9
Berea sand, Ohio[1]	6	7.0	16.8	12.0
Berea sand, Cabin Creek, W. Va.[1]	2	18.0	19.4	18.7
Bartlesville sand, Okla.[1]	4	16.1	17.7	16.8
Petrolia, Tex.[1]	4	18.5	26.6	22.9
Mexia-Groesbeck gas field, Limestone Co., Tex.[1]	8	10.7	37.7	24.4
Woodbine sand, Butter well, Shreveport, La.[1]	1	....	....	17.4
Salt Creek, Wyo.[1]	1	....	....	25.8
Nacatoch sand, N. La.-E. Tex	...	16.6	34.2	25.2
Wall Creek sand, Wyo.[2]	3	....	....	17.9
Shannon sand, Salt Creek, Wyo	...	....	....	26.7
Unconsolidated sands, Baku, Russia[3]	...	25.0	50.0	

[1] Compiled from data by MELCHER: "Determination of Pore Space of Oil and Gas Sands," *Min. and Met.*, No. 160, Sec. 5, Apr., 1920.

[2] WEGEMANN, C. H.: "The Salt Creek Oil Field, Wyoming," U. S. Geol. Survey, *Bull.* 670, pp. 27–28.

[3] THOMPSON, A. BEEBY: "The Oil Fields of Russia," p. 45, 1904.

Relative Saturation.[1]—The relative saturation of the oil sand depends upon (1) the amount of hydrocarbon or other gases present, and (2) the amount of water present. Hydrocarbon gases are ordinarily dissolved in the petroleum unless present in too great quantities, in which case they occupy the higher portions of the reservoir. Water may be mixed with the oil, taking up more or less space, depending upon the ratio of the mixture; it also occurs in the lower portions of the reservoir. The area underlain by gas, oil, and water can only be determined by drilling, although it is possible in certain cases to make estimates prior to the complete development of an area.

The following estimated average capacities of oil sands and factors of recovery for the various fields are given by Lewis:[2]

[1] Relative saturation may be defined as the percentage of the total pore space occupied by a given gas or liquid. If the relative saturation with petroleum is 10 per cent, then 10 per cent of the volume occupied by pore spaces contains petroleum.

[2] "Methods for Increasing the Recovery from Oil Sands," U. S. Bur. Mines, *Bull.* 148, p. 28.

Field	Factor of recovery, per cent	Capacity per acre-foot, barrels
Appalachian fields	12½	970
Illinois and Mid-Continent fields	17½	1,358
California fields	25	1,940

Factor of Recovery.[1]—Estimates of the percentage of recovery vary from 10[2] to 60 per cent.[3] Total recovery and hence the percentage of recovery vary with changing economic conditions; the factor of recovery is greater for high prices and low costs than where the opposite set of conditions prevails.

The size of the pore spaces greatly affects the factor of recovery. Openings in rocks may be classified into three groups; beginning with the largest, they are supercapillary, capillary, and subcapillary.[4] In supercapillary openings resistance to movement is least; the liquid moves most readily, and it is from such openings as these that oil is generally extracted. The movement of liquid is much slower and more difficult in the capillary openings and capillary attraction plays a very important rôle, while movement in subcapillary openings is almost impossible. There are no definite limits to the size of capillary openings; for water the upper limit has been given as one-fiftieth of an inch, although this is probably too small.[5] The size of capillary openings for oil is probably much smaller than for water.

[1] By "factor of recovery" is meant that portion of the oil content of a reservoir which may be commercially recovered.

[2] Lewis, J. O.: "Methods for Increasing Recovery from Oil Sands," U. S. Bur. Mines, *Bull.* 148, p. 26.

[3] Washburne, C. W.: "The Estimation of Oil Reserves," Am. Inst. Min. Eng., *Bull.* 98, Feb., 1915, pp. 469–471.

[4] If a glass tube of very small diameter, open at both ends, is held vertically with its lower half in water, the water will rise to a higher level inside the tube than outside. The elevation of the water surface inside the tube is greater for small tubes than for large ones and varies with the material composing the tube. If the liquid were mercury instead of water, the surface of the mercury inside the tube will be lower than that outside. Similar effects are noted between two vertical plates placed close together. The foregoing phenomena are classed under the heading of "capillarity." Openings in which the effects of capillarity are pronounced are termed "capillary openings"; larger openings are called "supercapillary" openings and smaller openings, "subcapillary."

[5] Meinzer, O. E.: Personal communication.

Assume that the three categories of openings exist in a given sandstone. If other characteristics remain constant, such as shape of grains and their arrangement, then the size of the pore spaces will vary directly with the size of the sand grains. If the sand grains are small, there will be a larger percentage of subcapillary openings and a smaller percentage of supercapillary openings than if the grains are large. Coarse-grained sandstones will consequently yield a greater portion of their oil than fine-grained ones.

The case appears to be different with unconsolidated sands where the sand is extracted along with the oil; the mere size of the grains apparently has little effect upon the yield of oil. Thompson[1] states that out of five samples of oil sands from Russian oil fields nearly all of the material passed through a screen with 80 meshes to the inch, and all of one sample passed through one measuring 200 meshes to the inch. Openings between such grains would ordinarily be of capillary or subcapillary size. Pack[2] reports grains of similar size in the Sunset-Midway field of California and states that the fine, uniform-grained sands are frequently more petroliferous than the coarser ones, which contain finer grains in the spaces between the larger grains, and consequently have lower porosity.

Application.—The saturation method is likely to give results which are too optimistic, unless a low coefficient of recovery is used. This method is useful in estimating the probable maximum yield in advance of drilling; it is also applicable to areas where only a few wells have been drilled and whose production curves show abnormally slight decline due to the absence of interference. Estimates based upon the saturation method may be valuable in preventing excessive initial investment, especially where the productive sands are few and very thin.

Acre-yield Method

Another advantage of the saturation method lies in its furnishing an analytical basis for the method of comparative acre-foot yields, which consists in applying yields of other fields to the field in question, using as a unit of measure the acre or acre-foot. (By "acre-foot" is meant a sand having a thickness

[1] Thompson, A. Beeby: "Oil Field Development," p. 107, 1916.

[2] Pack, R. W.: "The Sunset-Midway Oil Field, California," U. S. Geol. Survey, *Prof. Paper* 116, p. 80, 1920.

of 1 foot and 1 acre in area.) Acre-foot yields are determined by dividing the production per acre by the number of feet of producing sand. The chief source of error in the computation is in the determination of the thickness of pay sand. In the application of this method only similar fields should be compared; similarity should be based on those factors already analyzed in the discussion of the saturation method, namely, porosity, saturation, and coefficient of recovery.

The Maikop field of Russia is reported to have produced 2,355 barrels per acre-foot. The oil sands of Russia are very thick in places and, as a result, the yield per acre may be very high. Plot XIX of the Russian Petroleum Company, Ltd., in the Bibi Ebit field, produced more than 2,200,000 barrels per acre.[1] These yields are phenomenal and cannot ordinarily be expected. . The average yield per acre in the United States has been estimated as 2,350 barrels.[2] Typical acre-foot yields are 200 to 300 barrels. In the close-textured sands of the Illinois fields, the average acre-foot yield is estimated to be only slightly in excess of 100 barrels, while the average for the Bradford field, of Pennsylvania, is estimated as being materially under that figure. Acre-foot yields of 250 barrels have been reported from several of the Oklahoma fields. In the Homer field of Louisiana, acre-foot yields of 500 barrels or more are commonly reported.

[1] THOMPSON, A. BEEBY: "Oil Field Development," pp. 160–161, 1916.

[2] LEWIS, J. O.: "Methods for Increasing the Recovery from Oil Sands," U. S. Bur. Mines, *Bull.* 148, p. 29.

CHAPTER IV

PETROLEUM PRICES

Few commodities are subject to such severe and rapid fluctuations in price as petroleum. Thompson reports that in 10 years the price of oil in Baku, Russia, ranged from 22.4 cents to $1.50 a barrel, a range of nearly 7 to 1. In Galicia, in 1908, during the period of overproduction, due to insufficient transportation facilities, the price of crude was 20.8 cents a barrel, but in 1913 it was selling at $2.56 a barrel.[1] Within the first 3 years of the petroleum industry the range in prices was from $20 to 10 cents a barrel (see p. 97). During the period of Cushing overproduction the price of Oklahoma crude oil fell from $1.05 to 40 cents a barrel. The effect of this overproduction upon other fields is shown by the drop in Pennsylvania crude from $2.50 in the early part of 1913 to $1.35 by the middle of 1915. More recent changes are indicated by the drop of Pennsylvania crude from $6.10 to $3 in the first quarter of the year 1921, and, after a slight recovery, by a further reduction to $2.25 in the summer of that year. Mexia crude increased from 60 cents to $1.50 a barrel in a few months during the winter of 1921 to 1922. Within a month, from January 17 to February 17, 1923, the price of Smackover heavy increased from 30 to 90 cents. The full effect of these sudden fluctuations is realized when it is remembered that even slight changes in the price of oil may greatly affect profit, as the operating cost usually varies but little.

In spite of these severe fluctuations in the price of petroleum there are certain stabilizing influences. Substitutes place an upper limit upon the price of petroleum and its products. It is not likely that these prices will for long periods of time remain in excess of that price which would enable competing articles of trade to underbid it. Neither is it likely that development will long maintain its normal activity unless the price exceeds the total cost of obtaining the oil. Among the factors influencing the price of petroleum are its chemical characteristics, demand for

[1] Thompson, A. Beeby: "Oil Field Development," p. 51.

its various products, advances in refining technology, growth of rival industries, inability of the operator to curtail production adequately in times of depression, growth of the automotive industries, market facilities, and attempts to control production, or price, or both. A study of these factors and their influence upon past prices will serve as a useful guide in predicting future prices.

DEMAND FOR PETROLEUM

Characteristics of Petroleum

Chemical Composition.—Petroleum contains a large number of chemical compounds, all closely resembling each other and consisting essentially of hydrogen and carbon. Pennsylvania petroleum contains the compounds listed in Table VI. It should be noted that the simpler compounds[1] are gaseous, the more complex are solids, while the intermediate ones are liquid. Crude petroleum contains these solid and gaseous compounds in solution. An inspection of this table indicates a regular increase in boiling and melting points within the series from the simpler to the more complex members. Other characteristics vary with the same regularity; the simpler compounds are lighter and more volatile than the more complex ones. Petroleum contains the following series of hydrocarbons; they show the same regularity of variation in the physical characteristics of the individual members as the paraffin series.

Hydrocarbon Series in Petroleum[1]

1. C_nH_{2n+2}	6. C_nH_{2n-8}
2. C_nH_{2n}	7. C_nH_{2n-10}
3. C_nH_{2n-2}	8. C_nH_{2n-12}
4. C_nH_{2n-4}	.....
5. C_nH_{2n-6}	18. C_nH_{2n-32}

[1] Clark, F. W.: "The Data of Geochemistry," U. S. Geol. Survey, *Bull.* 695, 4th ed., p 721.

Impurities.—Sulphur and nitrogen are found in petroleum as impurities, the former has had a very marked depressing effect upon the price of petroleum.

[1] By a "simple" compound is meant one whose molecules contain but few atoms. The methane molecule (CH_4), for example, contains only one carbon and four hydrogen atoms, a total of five atoms. Pentatriacontane ($C_{35}H_{72}$) is an example of a complex compound; the molecule in this instance contains 35 carbon and 72 hydrogen atoms, a total of 107 atoms.

TABLE VI.—PARAFFINS[1] FROM PENNSYLVANIA PETROLEUM[2]

Name	Formula	Melting point, degrees C.	Boiling point, degrees C.
1. Gaseous:			
Methane	CH_4	−184.0	−165.0
Ethane	C_2H_6	−171.4	− 93.0
Propane	C_3H_8	−195.0	− 45.0
Butane	C_4H_{10}	−135.0	+ 1.0
2. Liquid:			
Pentane	C_5H_{12}	.....	36.3
Hexane	C_6H_{14}	.....	69.0
Heptane	C_7H_{16}	.....	98.4
Octane	C_8H_{18}	.....	125.5
Nonane	C_9H_{20}	− 51.0	150.0
Decane	$C_{10}H_{22}$	− 31.0	173.0
Undecane	$C_{11}H_{24}$	− 26.0	195.0
Dodecane	$C_{12}H_{26}$	− 12.0	214.0
Tridecane	$C_{13}H_{28}$	− 6.0	234.0
Tetradecane	$C_{14}H_{30}$	+ 5.0	252.0
Pentadecane	$C_{15}H_{32}$	10.0	270.0
Hexadecane	$C_{16}H_{34}$	18.0	287.0
3. Solid:			
Octadecane	$C_{18}H_{38}$	28.0	317.0
Eicosane	$C_{20}H_{42}$	37.0	
Tricosane	$C_{23}H_{48}$	48.0	
Tetracosane	$C_{24}H_{50}$	51.0	
Pentacosane	$C_{25}H_{52}$	53–54.0	
Hexacosane	$C_{26}H_{54}$	55–56.0	
Octocosane	$C_{28}H_{58}$	60.0	
Nonocosane	$C_{29}H_{60}$	62–63.0	
Hentriacontane	$C_{31}H_{64}$	68.0	
Dotriacontane	$C_{32}H_{66}$	70.0	
Tetratriacontane	$C_{34}H_{70}$	71–72.0	
Pentatriacontane	$C_{35}H_{72}$	75.0	

[1] Paraffins are hydrocarbons (compounds of hydrogen and carbon) whose formulas all conform to the general formula C_nH_{2n-2}. The formula of methane (CH_4) may be obtained by substituting 1 for n; that of ethane (C_2H_6) by substituting 2 for n, etc.

[2] Table VI is from BACON and HAMOR: "American Petroleum Industry," p. 3.

The best illustration of this is the case of Ohio oil. This contains about 0.75 per cent of sulphur, and, prior to the introduction of the Frasch desulphurizing process, was sold at 14 cents per barrel, while

Pennsylvania oil, with a sulphur content of only 0.03 per cent, sold at $2.25 at the same time.[1]

Classification of Petroleum.—Petroleum is classed as paraffin-base, asphalt-base, and mixed-base petroleum. Paraffin-base petroleum contains solid paraffin hydrocarbons and practically no asphalt; asphalt-base petroleum contains asphalt but no paraffin; mixed-base petroleum contains both paraffin and asphalt. Paraffin-base petroleum is found in the Appalachian field, asphalt-base petroleum in the California and Gulf Coast fields, and mixed-base petroleum in the Mid-Continent field. Petroleum of paraffin base is usually lightest in gravity and yields the greatest variety of lubricants. These two characteristics render it especially valuable, and consequently it commands the highest prices.

Refining.—The compounds found in petroleum vary greatly in their physical characteristics. Some of these compounds are well adapted for use as illuminants; others as source of power in internal combustion engines; others as lubricants, wax or fuel; but petroleum in its crude state is adapted to comparatively few uses. Its greatest usefulness can only be obtained by refining. The process of refining consists in grouping together similar compounds into separate products, each suitable for distinct uses.

Gravity.[2]—With the exception of the lubricant fraction,

[1] Bacon, R. F. and Hamor, W. A.: "The American Petroleum Industry," p. 609.

[2] In the petroleum industry the term "gravity" is used to express the heaviness of one grade of oil as compared with another. It is analogous to density and specific gravity, but it is usually measured in different units. Density is the mass (the equivalent of weight under certain specific conditions) of a unit of volume of a given substance. Specific gravity is the ratio of the density of one substance to a standard substance; water is usually used as the standard for liquids and solids. Iron has a specific gravity of about 7.6, which means that 1 cubic inch of iron weighs as much as 7.6 cubic inches of water.

The gravity of petroleum is expressed in degrees (°Bé.), Baumé, so named from its author Antoine Baumé, who first published his scale in 1768. As defined by the United States Bureau of Standards, the relation between the Baumé scale and specific gravity may be expressed by the following relations, assuming standard conditions for conversion:

$$\text{Degrees Baumé} = \frac{140}{\text{Specific gravity}} - 130$$

$$\text{Specific gravity} = \frac{140}{130 + \text{degrees Baumé}}$$

By substitution in the above formula it will be seen that a specific gravity of 1 represents 10°Bé., and a gravity of 45°Bé. a specific gravity of 0.8. As the numbers expressing specific gravity decrease, the numbers expressing degrees Baumé increase.

whose output is relatively small, those products most volatile and of the lightest gravity are of the greatest value. The three most important products arranged in the order of their value, lightness in gravity, and volatility, are gasoline, kerosene, and fuel oil, gasoline being the most valuable. Likewise, the value of crude petroleum varies according to gravity. The lighter oils have the greatest gasoline content and, consequently, command the highest prices. Most of the crude petroleum is now sold on the basis of gravity.

Petroleum Products [1]

The output of the four most important petroleum products,[2] gasoline, kerosene, lubricants, and fuel oil, together with the annual percentage increase in each, is shown in Table VII.

Gasoline.—The demand for gasoline has set the pace for all other petroleum products. The output of gasoline from American refineries has increased 17 per cent annually during the past 5 years, while the annual consumption of crude has increased only 10 per cent (see Table VII, p. 83). This demand for gasoline has led to encroachment upon the kerosene fractions, to the extraction of the gasoline content from natural gas, and to the "cracking" of heavy petroleum, thus producing a greater yield of gasoline.

The chief cause for this demand is the automotive industry, including passenger cars, trucks, and tractors, all of which

[1] A more detailed discussion of the demands for petroleum products may be found in "Economics of Petroleum," by Joseph E. Pogue.

[2] The following classification of petroleum products is modified from that used by the United States Bureau of Mines ("Properties of Typical Crude Oils from the Eastern Producing Fields of the United States," by E. W. Dean, Petroleum Chemist, "Reports of Investigations," *Serial* No. 2202, p. 3) in their analysis of crude petroleums;

1. The sum of all fractions distilling at atmospheric pressure below 200°C. (392°F.) is reported as *gasoline and naptha.*

2. The sum of all fractions distilling at atmospheric pressure between 200°C. (392°F.) and 275°C. (527°F.) is reported as *kerosene.*

3. The sum of all vacuum distillation fractions having Saybolt viscosities (at 100°F.) of less than 50 seconds is reported as *gas oil.* This also includes any fuel oil obtained in the process of refining.

4. The sum of all vacuum distillation fractions having Saybolt viscosities (at 100°F.) of 50 seconds or more is reported as *lubricating distillate.*

consume approximately four-fifths of the gasoline produced. The dominance of the automotive industry has created a seasonal demand for gasoline, greatest in summer.

TABLE VII.—OUTPUT OF AMERICAN REFINERIES IN 1922[1]

Product	Output in 1922		Annual percentage increase 1917–1922
	In billions of gallons	Per cent of total	
Crude petroleum	23.3[2]	100	10
Gasoline	6.2	27	17
Kerosene	2.3	10	6
Gas and fuel oil	10.7	46	10
Lubricating oils	1.0	4	5
Wax, coke, asphalt, miscellaneous, and losses	....	13	

[1] Prepared from "Refinery Statistics for 1922," U. S. Bur. Mines, compiled by W. C. Hill.

[2] Consumption of refineries converted from barrels into gallons.

Kerosene.—Kerosene was once the most important petroleum product; today it occupies a secondary rank. While the crude oil consumed by American refineries has increased 10 per cent annually during the last 5 years, the increase in kerosene output has been only 6 per cent.

The principal use of kerosene has been, and still is, as an illuminant; however, of late years there has been an increasing use for kerosene in motors of various sorts, particularly in tractors. These two demands are also seasonal in character, that as an illuminant being dominant. The demand as an illuminant is greatest in winter, and as a source of power in summer.

Much of the kerosene now refined in the United States is exported.

Fuel and Gas Oil.—In areas with insufficient coal supply, as many of the states west of the Rocky Mountains, petroleum is used in railroad locomotives, in stationary engines, and also as a source of artificial gas. Due largely to the unstable conditions prevailing in the coal industry and the inability to obtain coal when most needed because of strikes, oil is being used more

and more for heating purposes, especially in large buildings. But the chief advantage of fuel oil is in connection with marine transportation, where the increased radius of steaming and saving in labor and storage space are of great value. The conversion of the world's shipping from the use of coal to that of oil has been rapid and spectacular—this use of fuel oil has increased tenfold in the last 10 years. The demand for fuel and gas oil has kept pace with the rapidly increasing consumption of crude petroleum.

Lubricating Oil.—Lubricants are required wherever machinery is used. Their chief source is petroleum, Pennsylvania products holding first rank. The early development of the petroleum industry and petroleum technology in the Appalachian field has been of great advantage to oil producers in this field, but this advantage is gradually disappearing. In spite of the widespread use of lubricants their demand is not keeping pace with the consumption of crude oil.

Relation to Transportation.—As previously noted, petroleum products are particularly well adapted for use as a source of power in transportation. Both marine and railroad transportation exert heavy demands upon fuel oil, while the automotive industry not only dominates the demand for gasoline but, through it, that of crude oil as well; it uses approximately one-half of the petroleum products by value and one-fourth by volume. The use of automotive vehicles, including automobiles, trucks, tractors, and airplanes, is increasing at a phenomenal rate. Nevertheless, the saturation point probably has not yet been approached by passenger cars, and certainly not by the others.

Substitutes.—Coal, coal products, alcohol, and oil shale distillates are all possible substitutes for petroleum products; however, at present prices the petroleum industry need have no fear of severe competition from any of these sources. Fuel oil is at present replacing coal; not coal, fuel oil. Alcohol and coal products, such as benzol, are at present produced in very limited quantities when compared with the demands placed upon gasoline. Even during the stimulus of war conditions the total output of denatured alcohol and benzol was approximately only 1 per cent of the output of gasoline in 1922, which was more than 6 billion gallons.

The coke industry, from which benzol is obtained as a by-product, would have to be greatly transformed and augmented

before benzol would be a serious competitor with gasoline. The use of alcohol in large quantities not only would require the growth of a great industry for its production, but its introduction as a source of power would render present types of engines obsolete, as an almost distinct type of engine is required for its use. But the smaller output of benzol and alcohol may serve a useful purpose in blending with gasoline.

The reserves of oil shale are great, but the oil shale industry is still in its experimental stage in the United States. This industry entails great initial investment and high operating costs, and would hardly be profitable with the present prices of petroleum products.

With a growing automotive industry and increasing demands for fuel oil, and with most of the potential substitutes still in their industrial infancy, it would hardly appear that petroleum need fear a market for its products. However, the possibility of using substitutes places an upper limit upon the price of oil, above which it will not advance. This is especially true of the heavier grades used primarily for fuel oil and which, consequently, come into active competition with coal.

Demand for Petroleum by Refineries

The demand for petroleum products is the basis for the ultimate demand for petroleum, but competition among refiners forms the basis for the immediate demand. Most of the petroleum of the country is purchased at posted prices; these prices are announced or posted by the large refining and marketing companies. Adjustments, of course, are made for unusual conditions, such as premiums on better grades of oil, and in some cases for pipe line charges.

The competition for crude oil may develop into a conflict between the large purchasing companies and small refineries. The small refining company will offer a premium; the posted price will be raised to meet that premium; as a result, a new premium is offered with respect to the new price and the posted price again revised. This was one of the elements entering into the sudden increase of price of Pennsylvania crude from $4 to $6.10 a barrel in the early part of 1920.

SUPPLY OF PETROLEUM

Immediate Supply

A distinction should be made between the immediate and ultimate supply of petroleum. In general, it is the immediate supply, consisting of the oil in storage and present production, that controls prices. The prospect of future production for the next few months or year and prevailing opinions concerning the ultimate production, at times, have an important effect upon prices, but their rôle is usually secondary.

Oil in Storage.—Oil in storage represents the excess of production over consumption, and serves as a barometer of equilibrium between supply and demand. A study of the increase and decrease in the stocks of petroleum and its products is of the greatest importance in predicting future prices. Variations in the amount of oil in storage may be due to fluctuations in either supply or demand; certain changes are normal and have relatively little significance so far as prices are concerned, while other changes have a decided bearing upon prices.

Normally, stocks increase in winter and decrease in summer, in accordance with the seasonal demand. Normally, stocks may be expected to increase sufficiently from year to year to keep pace with the annual increase in consumption. Neither of these changes has great significance so far as prices are concerned.

The maintenance of a normal increase in the amount of stored petroleum from year to year, in the face of increasing demands, necessitates the discovery of new pools, as the production from the old ones, while fairly constant, is slowly declining. The production of oil from new pools increases rapidly until the peak is reached, and while the decline is also usually rapid, it may be some time before the production falls to the point of consumption, and longer yet before the surplus stocks of crude oil and their products have been exhausted. Ordinarily, the factors which are of the greatest significance in affecting prices are changes in the amount of oil in storage, due to the rise and decline of new pools.

Overproduction.—When a new pool is discovered, the development is usually rapid until all offset and line wells are drilled. Until this result is attained it is commonly impossible to curtail development regardless of the price situation.

Given the following conditions on 640 acres of oil land, where 16 companies each own 40 acres:

A	B	C	D
E	F	G	H
I	J	K	L
M	N	O	P

This is by no means an exaggeration. Companies owning as little as 10 acres or 20 acres are not uncommon. When *A* drills a well in his southeast corner, *B*, *E*, and *F* must drill offsetting wells or suffer their property to be drained. For every corner well so drilled, three other corner wells must be drilled, and for every line well, an offsetting well must be drilled in self-protection. In time of overproduction, *F* cannot afford to shut down, because *A*, *B*, *C*, *G*, *E*, *I*, *J*, and *K*, or any combination of them, may refuse to do likewise. It follows that the oil in the ground of *F* is not only extracted by his neighbors, but the underground flow is diverted from his wells, with resultant loss in daily production when he again starts up.

In other words, curtailing or entirely suspending production is viewed by the oil man as a calamity and only to be considered on large tracts and on wells remote from boundary lines.

Because of these conditions, curtailment of production comes only as a result of curtailed drilling operations and natural decline of producing wells. In the case of the last California surplusage it required 5 years to correct the evil, during which time conditions have been so acute that proposals were made to burn large quantities of oil to relieve the congestion and advance the price.[1]

Overproduction may be local and exist only in the sense that transportation facilities are inadequate. The markets are not demoralized, comparatively little oil has been stored, and the effect upon prices is not widespread. The price history of oil is one of gradual increase. Overproduction occurs in the initial stages and, consequently, the first prices posted are the lowest.

[1] REQUA, M. L.: "Petroleum Resources of the United States," *Senate Document* No. 363, pp. 16–17.

Overproduction may exist with respect to only one type of petroleum, as fuel oil. The price of competitive grades of oil may be depressed, while the effect on the lighter gravity oil is negligible.

Relation of Drilling Activity to Prices.—While the drilling of offset wells cannot be delayed regardless of the price situation,

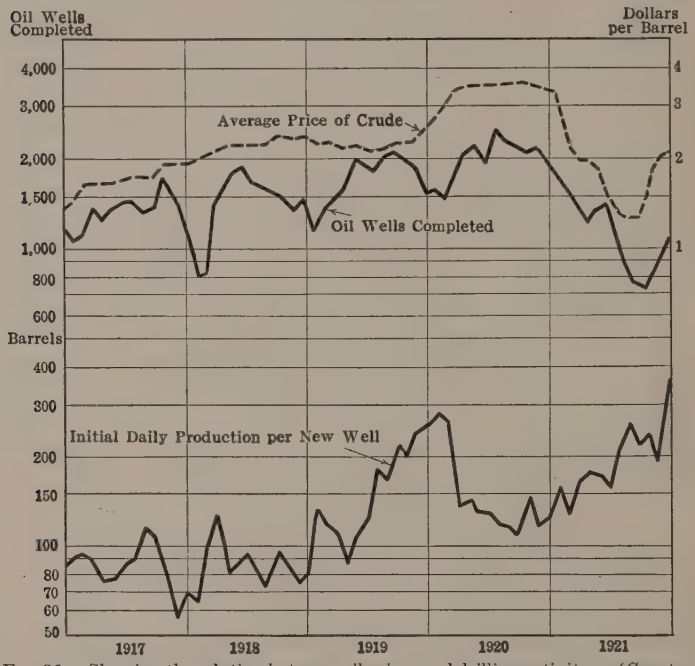

FIG. 36.—Showing the relation between oil prices and drilling activity. (*Courtesy of J. E. Pogue; reprinted from article in the New York Evening Post*).

the drilling of interior locations and of wildcat wells may usually be postponed until the conditions are again favorable. All classes of wells are shown in Fig. 36,[1] which shows the response

[1] Arithlog or semilog paper is here used for plotting prices of petroleum. In this type of paper the horizontal distances between sucessive rulings are equal but the vertical distances between rulings are based upon the logarithms of the numbers which the rulings represent.

Graphs drawn on this paper give the same importance to the same relative changes in price; that is, a change of 10 cents when oil is quoted at $1 a barrel and of 50 cents when oil is quoted at $5 a barrel are given equal weight and are indicated by equal vertical distances in the diagram. Abso-

of drilling activity to the price of oil. As drilling of offsets responds but little to changes of price, the response of drilling activity of other types of wells to price changes is correspondingly greater than that indicated in the diagram.

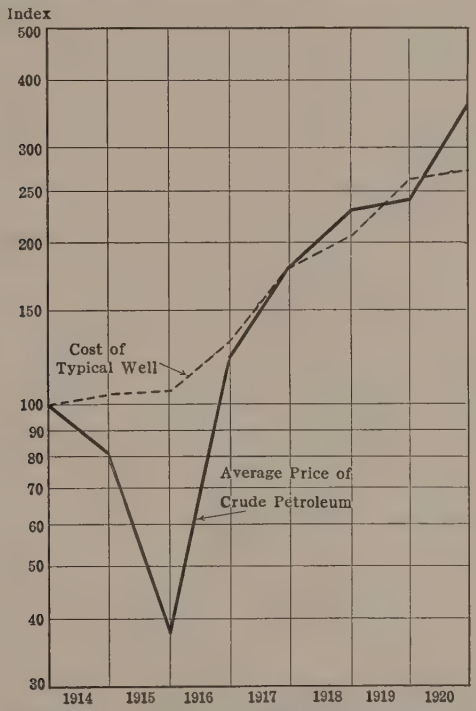

FIG. 37.—Comparison of the increase in cost of a typical well with the increase in price of crude petroleum in the Mid-Continent Field, 1923–1920; data from Bates and Lasky. (Figures for 1913 = 100.) (*Reprinted by permission from Pogue's "Economics of Petroleum" published by John Wiley & Sons, Inc.*)

Cost of Production.—The bulk of the oil is produced by large companies operating on a sound financial basis, and while for brief periods of time the price of oil may fall below the cost of

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lute quantities can be read from the scale on the margin. For a further discussion of this type of chart see:

FISHER, IRVING: "The Ratio Chart for Plotting Statistics," *Quart. Pub.* of the Am. Statistical Assn., June, 1917, p. 557.

FIELD, J. A.: "Some Advantages of the Logarithmic Scale in Statistical Diagrams," *J. Pol. Econ.*, vol. 25, pp. 805–841, 1917.

operation, this condition could not continue indefinitely. The cost of production, then, forms a lower limit to the price of oil, below which it will fall only occasionally. These occasional periods may, however, be quite sufficient to wreck many of the weak oil concerns. An increase in the cost of production will ultimately necessitate an increase in the price of oil; increased costs was one of the reasons given by the petroleum industry to show the necessity of increased prices in 1920. The parallel movement of cost of drilling and price of oil is shown in Fig. 37.

It should be noted that for the period 1914 to 1920 the cost of drilling increased at the same rate as the price of oil; both in a large measure were due to the prevailing tendencies in economic conditions. This can readily be verified by comparing the increasing price of Appalachian crude with increase in the index numbers (see Fig. 38).

Ultimate Supply

The immediate supply is the most effective factor in the present determination of price, yet it is quite possible that at some future date the price of petroleum will be influenced by the exhaustion of the reserves.

Fear of Shortage.—Even the fear of a shortage of petroleum, although not based on a firm foundation of fact, may have an important temporary effect upon the price of oil; but such an effect is bound to be followed by a reaction. The Federal Trade Commission considered that this psychological factor was of prime importance in the increase of prices in the beginning of 1920.[1]

> It seems that there is greater justification in assigning the advance in price of crude oil and petroleum products to varying conditions of supply and demand in the light of emphasized and pessimistic statements as to future of supply than of a combination in restraint of trade. . . . .
>
> The explanation of the men of the oil industry regarding the reasons for the advance in the price of crude oil—namely, the strong demand for crude oil, the decline in stocks, the increasing consumption during the last half of 1919 and the decreasing production during the last quarter of 1919, the increased costs of drilling and producing crude oil, and the unfavorable developments in the Mexican oil field—has substantial force, especially in 1919, but it should be noted that the conditions

[1] Federal Trade Commission: "Advance in Price of Petroleum Products."

in 1920 appear to have greatly improved with respect to production and imports. It is also the opinion of the Commission that the psychological factors in the situation were more important than the actual statistical position, the mental attitude of the oil trade being strongly affected on the one hand by the frequent statement that there was an impending decline of production in the United States, which was aggravated by the sudden slump of the north Texas output in the middle of 1919 and by the unfavorable development industrially and politically in Mexico in the autumn of that year.

Estimates of Future Supply.—Various estimates of the petroleum resources of the United States have been made. The most recent was made by the United States Geological Survey in cooperation with the American Association of Petroleum Geologists.[1] It gives 20 years' future supply at the present rate of consumption. Such an estimate can be based only upon numerous assumptions, one of which is that present methods of extraction, by which probably not more than 20 per cent of the oil content of the sand is extracted, will continue in the future. The difficulties of estimating the future reserves of the undiscovered fields are so great that the value of such a prediction is greatly reduced, even when made by some of the best geologists of the country.

THE DOLLAR AS THE UNIT OF PRICE

Nature of Units.—Definite units, such as the second, the foot, and the pound, have been established for the measurement of time, space, mass, and other physical quantities. If a building is determined to be 127 feet long, it will be found to have the same length 5 years hence. If it requires $2\frac{2}{5}$ seconds for a stone to fall from a certain tower before striking the ground, the same result can be obtained at any future time. Neither is there any change in the mass of an object when measured in pounds.

At no time has a constant unit been established for value. Skins of animals, leather, oxen, beads, whale's teeth, corn, cocoanuts, tobacco, cubes of beeswax, and many of the metals have all been employed; but each of these units is a commodity and, as such, it is subject to change in value. The gold dollar is now the accepted unit of value, and changes in prices are frequently

[1] A complete report on the estimate is found in *Bull.* of the American Association of Petroleum Geologists, vol. 6, no. 1, p. 42. Criticism of this report by DeGolyer appears in *Economic Geology*, Jan.-Feb., 1922, vol. 17, No. 1, p. 40.

due to the fluctuation in the value of the dollar. If I buy 10 pounds of sugar for a dollar today, next week I may be able to buy only 8 pounds for a dollar, and next year only 5; or the number which I can purchase may increase. Farmer Jones said, "A dozen eggs will not buy as many nickels as it used to."

Quantitative Theory of Money.—If a given commodity is scarce it commands a greater amount of goods in exchange than if it is common. More goods can be purchased for $1 when gold is scarce than when it is plentiful, and, conversely, high prices prevail when gold is plentiful. Other forms of money and credit are the basis of many of our transactions. When credit is easily secured the result is the same as plentiful money—high prices prevail. If credit is suddenly threatened, a rapid drop in prices is the logical result; such a situation occurred in the spring of 1921.

Index Numbers.—The fluctuation in the value of the dollar is reflected by an index number, which is the average price paid for a group of commodities. Usually they are so expressed that the index number of the base year is 100. An index number of 110 for a given year means that prices in general are 10 per cent higher than in the base year and that the value of the dollar is correspondingly lower.[1]

Application to Petroleum.—With change of prices, the fluctuations are most violent in raw products, of which petroleum is an example. The index number which records the fluctuation in all prices will not be so severely affected as the price of a raw product, although this fluctuation will be greater than the average fluctuation in price of finished products.

The effect of the varying value of the dollar (recorded in the index number) upon petroleum prices will be seen in Fig. 38. In general, the index number and price of petroleum show parallel fluctuations, but the severity of fluctuations in the price of petroleum is much the greater, which is in accord with the principles already stated.

ARTIFICIAL FACTORS

Small vs. Large Companies.—Considerable controversy exists concerning the cause for sudden price changes of petroleum.

[1] The reader is referred to *Bull.* of U. S. Bureau of Labor Statistics No. 284, "Index Numbers of Wholesale Prices," for the construction and use of index numbers.

Large and small operators have both been blamed for this condition. The large marketing companies are often accused of encouraging drilling activity by increased prices, and later, when the desired production is obtained, of cutting prices. Drastic cuts are usually ascribed by the small operators to some of the larger interests, stating that such cuts are made primarily to drive them out of business and force them to sell their properties to the large interests at a loss. On the other hand, the lack of financial reserves necessary for storing oil and the necessity of immediate sales by small companies tend to force surplus stocks on a market already demoralized. The practice of stock selling companies leasing and drilling only a few acres, primarily for advertising purposes, and town lot development, all aggravate this condition.

Mid-Continent Oil and Gas Association.—Storing of oil, the creation of greater transportation facilities, curtailment of oil runs by pipe-line companies, the creation of purchasing agencies, and Governmental regulations have all been invoked during periods of depression in the attempt to stabilize prices.

A very interesting attempt to regulate prices is that of the Mid-Continent Oil and Gas Association in its efforts to curtail production. The association has no legal authority to enforce its demands: nevertheless, it has been at least partially successful in inaugurating and maintaining shut-down movements. Operators are urged to limit drilling to offset wells and to those wells already begun or contracted for, prior to the inauguration of the shut-down movement.

Union-Agency of California.—The Union-Agency of California attempts to obtain more favorable prices through its creation of better marketing facilities. The Independent Oil Producers' Agency is composed of nearly 200 companies restricted largely to the San Joaquin Valley field. The agency disposes of the oil of its various members through a contract with the Union Oil Company, which sells the oil along with its own on a commission basis.

United States Government.[1]—During the World War it became necessary for the Government to control the prices of

[1] For a more detailed account of the Federal control of the price of petroleum see "Prices of Petroleum and its Products During the War," by Joseph E. Pogue of the Oil Division, U. S. Fuel Administration, assisted by Isadore Lubin of the War Industries Board.

commodities. The Oil Division had broad powers of control over petroleum prices under the authority of the Food and Fuel Act of August 10, 1917. These powers were never fully called into action, as the oil industry acting through the National Petroleum War Service Committee agreed "to stabilize prices and maintain an uninterrupted flow of crude." The plan was effective for 4 months—from August 9, 1918, to December 12, 1918. Prices were stable during this period, but other factors may have been effective, as prices remained stable for a much longer period of time.

Galicia.—Galicia afforded an interesting example of attempts to defeat depression in 1911, when the output of the famous Boryslaw-Tustanowice oil field had quite outgrown its usual markets. As an example of the extent to which operators are willing to relinquish their position at moments of difficulty, the case is especially instructive. When crude oil prices were low, refiners made large profits at the expense of the producers, but when the price of crude oil rose, the profits of refiners were seriously diminished. When struggling producers induced the authorities to erect large storage for surplus crude oil, and to make advances on oil put into storage, the price and output of crude oil rose rapidly, and refiners were working at a loss. Burdened by a tax of £6, 8s. per ton ($4.09 per barrel) on illuminating oil, home markets were restricted in view of the agreement of refiners to maintain a fixed price for home sales.

Surplus oils were thrown on the German market at any price they would fetch, thus arousing the antagonism of the Standard Oil Company, who promptly retaliated by undercutting the Austrian home market. So fierce became competition that negotiations for an agreement were opened.

The Austrian Government was led to intervene and purchase 1,500,000 tons of fuel oil for the railways at a price of nearly 24s. per ton (77 cents per barrel), but this caused but temporary relief, and crude oil prices fell to 5s. per ton (16 cents per barrel), at which moment the Standard Oil Company offered to expend £250,000 on storage tanks of a capacity of 1,000,000 tons. They tendered an advance on stored oil, but demanded the exclusive right of light distillates obtained in the preparation of fuel oil. Negotiations were cut short by the intervention of the Austrian Government, who realized what the producers were parting with, and they themselves decided to install storage on a large scale, and puchase more fuel oil. The immediate result was a leap in the price of crude oil from 6s. 8d. to 29s. per ton, 20.8 to 92.8 cents per barrel, and once more the refiners found themselves unable to fight the aggressive attacks of the Standard Oil Company when the stocks of

cheap oil became exhausted. The Austrian Government was subsequently led to introduce legislation of such far-reaching character that the Standard Oil Company was practically compelled to close down its refineries in Austria, a situation which diplomatic representation failed to remedy.[1]

HISTORY OF PETROLEUM PRICES

Appalachian Crude

A study of the price history of the United States reveals many interesting economic facts. Appalachian crude with its long history of production is first discussed, which is followed by a comparison with other grades. The annual output of oil from the United States, the average yearly price of Appalachian crude, and annual index numbers are plotted in Fig. 38.

General Trend.—There is a general decline in petroleum prices from 1864 to 1892, which is followed by a general increase. Similar trends will be observed in the index number. As previously noted, the index number records the purchasing power of the dollar, and the indicated variations in the purchasing power may be considered responsible for the observed trends in petroleum prices. Price predictions based upon general trends must take into consideration the future changes in the value of the dollar.

Cyclic Fluctuations.—The general trend of petroleum prices is greatly obscured by fluctuations, especially in the early part of the industry. Low prices occur at intervals of from 4 to 7 years, averaging every 5 years, with intervening periods of high prices. The years of low prices are 1861, 1867, 1874, 1879, 1882, 1887, 1892, 1897, 1901, 1905, 1911, 1915, and 1921; the intervals between these periods, in terms of years, are 6, 7, 5, 3, 5, 5, 5, 4, 4, 6, 4, and 6 respectively. (The year 1884 was not included as a period of low prices, as the decrease was so slight.) This regular occurrence of high and low prices, every 4 to 6 years, is of the greatest significance in price predictions. In two-thirds of the cases these variations are in accordance with similar variations in the index numbers.

In the early history of the petroleum industry, low prices coincide with increased production and high prices with decreased production. In later years other factors have somewhat obscured this relation. However, locally the effects of overproduction are quite marked and the period of Cushing overproduction and the

[1] Thompson, A. Beeby: "Oil Field Development," pp. 59–60.

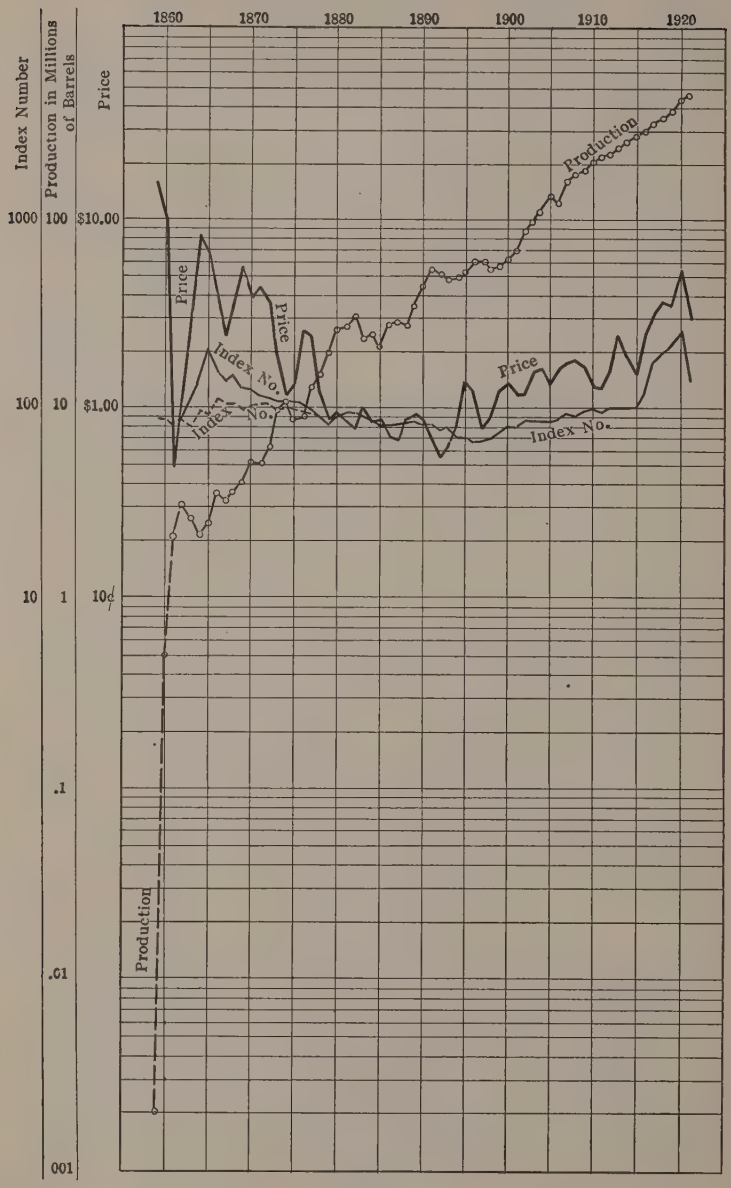
Index Number
Production in Millions of Barrels
Price
1860
1870
1880
1890
1900
1910
1920
1000
100
10
100
10
1
$10.00
$1.00
10¢
.1
.01
.001
Production
Price
Index No.
Price
Index No.
Price
Index No.
Production

Fig 38.

present (1923) period of California overproduction have both had very pronounced and wide-spread depressing effects upon prices.

Early Unstable Conditions.—The history of petroleum prices is marked by several important events beginning August 28, 1859, with the discovery of oil in Oil Creek, Pennsylvania. In less than 2½ years, from September, 1859, to December, 1861, the price of Pennsylvania crude fell from $20 to 10 cents a barrel, a range of 200 to 1. This range in price, which constitutes the record for the American petroleum industry, was the result of a highly unstabilized condition. The increase in production was even greater than the range in price, the production in 1859 was 2,000 barrels and for 1861 it was in excess of 2,000,000 barrels. High prices stimulated this overproduction, which, in turn, caused the most drastic price cut ever known to the industry. The response was natural, new development was curtailed, but the evil effects of overproduction could not be remedied at once, as shown by an increased production in 1862, which, however, was followed by a decline in 1863 and 1864. A second maximum was attained in July, 1864, with crude oil selling at $14 a barrel, due to decline in production and to war conditions. The effect of war conditions is recorded in the decrease of the value of the dollar and the consequent increase in the price of all commodities, as indicated by the index number.

During the unsettled conditions following the war, the price of oil showed great fluctuations and high prices, but by 1880 the excessive fluctuations in prices had largely disappeared. The price of all commodities, including petroleum, declined until 1892. With the advent of the automobile, the price of petroleum rose more rapidly and started sooner than that of other commodities.

Cushing Overproduction.[1]—The year 1913 was characterized by high prices which stimulated a country-wide drilling campaign and resulted in the opening of the prolific Cushing pool. The effect on prices, due to overproduction from this pool, was not

[1] An excellent description of the history of crude prices from 1913 to 1921 inclusive, is given by POGUE in "Economics of Petroleum," pp. 238–241.

FIG. 38.—Diagram showing the relation between the price of oil, production, and index numbers. The dashed line connecting the small circles indicates the total production by years of the United States. The heavy solid line indicates the average yearly price of crude oil of the Appalachian Field. The light solid line indicates the average yearly index numbers (based upon United States currency). The dotted line, shown only for the period 1862–1878, indicates the index number based upon the gold dollar.

confined to Cushing and Mid-Continent oil, but a decline to a little more than one-half of the previous prices occurred in all fields east of the Rocky Mountains.

War Period.—In addition to the normal recovery from the Cushing overproduction, there was an increase in the index number of 150 per cent from 1915 to 1920; during this period the price of Pennsylvania crude increased about 300 per cent. As the price of raw products varies much more rapidly than that of manufactured goods, the foregoing relative increases are entirely normal. This increase for 5 successive years resulted in prices that had not been attained since January, 1869, and constituted the greatest range in prices of Pennsylvania crude since the early years of the industry; it was the result of a series of small increases. However, from the early part of 1918 to the middle of 1919 the price of oil remained at $4 per barrel, and it was within this period that the plan of voluntary stabilization, previously described, was effected.

Post-war Period.—In the boom of 1920, oil attained the highest prices of recent years, selling at $6.10 a barrel. Operators were optimistic, drilling was carried on with feverish excitement, and old abandoned properties were rejuvenated. The price of oil remained constant for nearly a year; then within a few months it dropped to its 1916 level, a drop in price greater even than that at the time of the Cushing overproduction, and one that has occurred but a few times in the history of the industry. This drop was due to business depression and the flooding of the country with Mexican oil. With a decline in Mexican production and the improvement of business conditions generally, the price of oil reacted favorably, to be followed by minor cuts in the summer of 1922. In the spring of 1923, when prices were beginning to respond favorably, overproduction in California caused prices to be cut again, and delayed the long-expected return to prosperity.

Other Fields

The early history of most of the major oil fields was characterized by small output, great demand, and high prices. As production increased, the supply sooner or later exceeded local demands and came into competition with oil from other fields for outside markets. When this occurred, the oil was affected by the same economic conditions that influenced oil from other fields

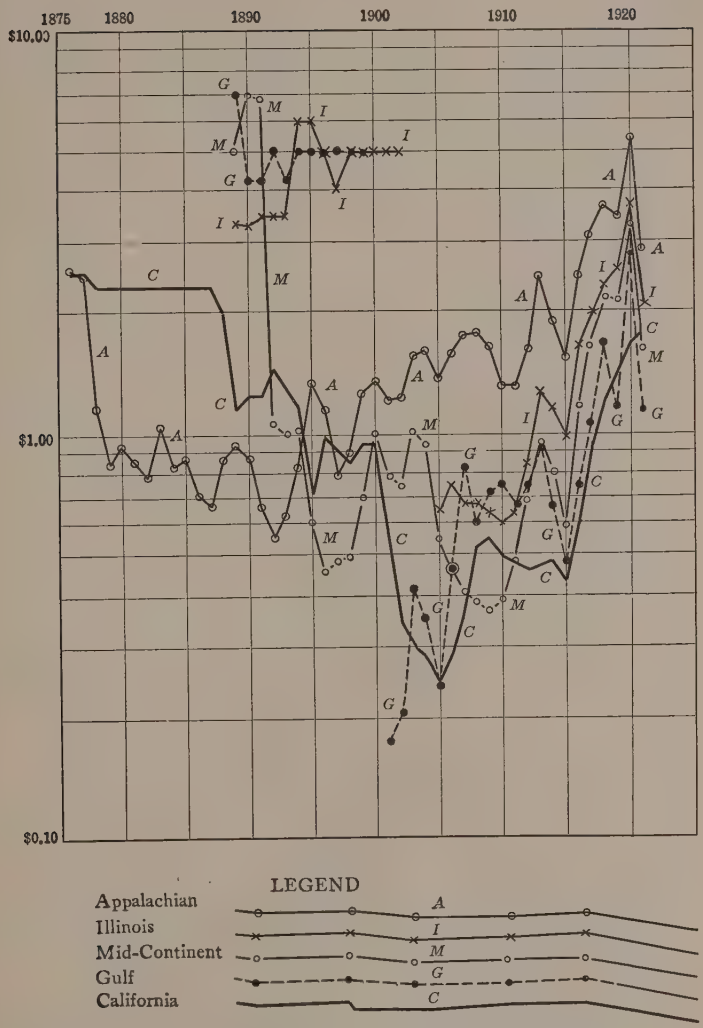

FIG. 39.—A comparison of prices of crude oil from various fields.

and showed a similarity to the other oils in their price history. The history of prices of crude oil from the Appalachian, Illinois, Mid-Continent, and California fields is shown in Fig. 39.

High prices prevailed for California crude until 1895, for Illinois crude until 1902, and for Mid-Continent crude until 1892. During these periods any fluctuations in the price were due entirely to local conditions, and showed no relation whatever to the changes in the price of Appalachian crude during this same period. These periods were terminated by great increases in production. Prior to 1895, California production never exceeded 705,969 barrels, but for that year the production was 1,208,482 barrels. Illinois production never exceeded 1,460 barrels prior to 1902, but in 1905, the production was 181,084 barrels. During the first few years of the life of the Mid-Continent fields, production did not exceed 1,430 barrels, but the 1894 production exceeded 40,000 barrels.

Beginning with the time of increased production, price changes in oil from these fields parallel the price movements of Appalachian crude, although certain exceptions may be noted. The period 1902 to 1907 exhibits unusually low prices in California, where the increase in production obscured the effects of the general market conditions, normal prices prevailing elsewhere. Due to its geographic isolation, independent marketing conditions, and differences in the grade of oil, only a slight reduction in California crude occurred at the time of the Cushing overproduction. The Mid-Continent field, because of local oversupply, was unaffected by the general high prices which prevailed from 1906 to 1910.

PREDICTION OF PRICES

Factors Affecting Prediction

"A little knowledge is a dangerous thing." This statement finds no better application than in the prediction of prices of petroleum. An analysis of the conditions to which predictions of prices are to be applied, and of the controlling forces, are necessary preliminaries to sound prediction.

Rapidity of Decline.—A definite distinction should be made between wells and properties showing a rapid decline, and those where the decline is very gradual or negligible. The value of the first type of property will be little affected by the price

of oil 5 years, and in many cases, 1 or 2 years, hence, while prices equally removed in time would play an important part in valuing properties of the second class. If the decline is very rapid, the greater portion of the oil may be obtained within the first few months; it may then be safe to assume a constant price of oil, unless price conditions at the time are highly unstable. If the decline is negligible, an average price may be predicted for a period of several years, and the result used in the appraisal. In the absence of either extreme, it may be advisable to predict prices for each year.

Premiums.—Premiums may be paid for a superior quality of oil or because of competition among refiners and purchasers. An analysis of the oil, including the determination of its gasoline and lubricating content, the percentage of impurities present, especially sulphur, and a comparison of such analyses with those of oils not receiving the premium, together with an examination of market conditions, will usually reveal the cause of the premium. Premiums paid by small refiners to secure a supply, during periods of great demand, must be considered temporary, while premiums based upon a superior grade of oil may reasonably be assumed to continue into the future.

Contracts.—Contracts may stipulate the purchase of oil at a fixed price, at a posted price, or at a premium above the posted price. The prospective purchaser may have control over the posting of oil prices; under these conditions, a contract to sell oil at the posted price or at a premium above that price places the seller at the mercy of the purchaser.

Methods of Prediction

Several methods may be used in predicting future prices of petroleum. Those most commonly employed are:

1. Use of a constant price.
2. Analysis of present conditions and predictions of the next change in price.
3. An historical study of past prices and determination of probable price trends.

Constant Price.—Prices do not long remain constant. Within the last 7 years, the price of Caddo heavy changed approximately 30 times, and the average annual range in price was more than 2 to 1. Similar examples can be quoted from other fields.

Very evidently the use of a constant price in appraisals throughout the productive life of the property rests upon an assumption seldom realized. Where decline is rapid the price at date of valuation may be used, but where the decline is negligible an average price extending over a period of years may be used.

Regardless of how carefully an average price may be determined, there will be years when the actual price is materially below the average and other years when it is materially above; these variations will be largely compensating if the decline is slow and production nearly constant for a long period of time.

The method of average prices was developed in connection with mine valuations, where the output could be regulated, or was nearly constant; at least there is not the rapidity of decline in output so common to many, if not most, oil properties.

Analysis of Present Conditions.—Price prediction beyond a period of a few years is relatively unimportant when the bulk of the production is extracted within the next year or two. Present conditions may be analyzed to determine the direction and extent of the next change, or set of changes, in price; the factors to be studied have been enumerated.

Price Trends.—The method of price trends consists in determining the past trend of prices and applying this past trend to the prediction of future prices. Past prices are plotted, trends are determined, and extrapolations made graphically. Although quadrille paper can be used, semilog (also called arithlog) paper[1] is preferred. In Fig. 40, the light solid line indicates the average price of Pennsylvania oil for the last 23 years, the heavy solid line represents the trend for the period 1900 to 1914, and the dashed line indicates the extrapolation. It will be noted that the extrapolation does not agree with actual prices, the divergence being due primarily to the World War with its increased prices. If, however, a general trend had been plotted for the period 1900 to 1909, its extrapolation could have been successfully applied as the basis of price predictions for the period 1910 to 1916, the fluctuations for these years being both above and below the extrapolated trend.

The underlying assumption of the method of price trends is that economic forces effective in the past will continue into the future—that the past prices are a guide to future prices. These trends are due largely to variations in the value of the

[1] See footnote p. 88.

dollar, and probable future changes of the dollar must be considered when applying this method.

Cyclic variations in prices cause much difficulty both in the estimation of past trends and in their application to future prices. Difficulties in the determination of price trends are apparent as shown by the differences in the estimates of various engineers. These estimates vary from an annual increase of 2 to 22 per cent. Price trends based upon short periods of time,

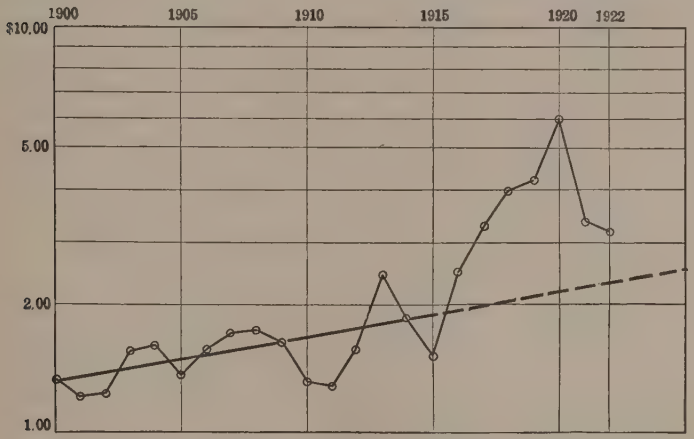

FIG. 40.—Method of trends applied to price prediction. Light solid line connecting small circles indicates the average price of Pennsylvania crude. The heavy solid line indicates the generalized price trend for the period 1900–1914. The dashed line indicates the extrapolation.

if applied at a time of peak prices, will give very erroneous results, and the graphic methods employed lead to a false sense of their reliability. This method may best be applied to properties with settled production, where the rate of decline is slight.

Errors.—The problem of price prediction has often been approached from only one viewpoint; the failure to consider any one of the numerous factors controlling prices may result in error and severe financial loss. Declining production and the application of discount factors greatly reduce the effect of errors. Few problems in the petroleum industry are more difficult than price prediction, and the services of men of sound judgment and broad experience should be sought.

CHAPTER V

THE VALUE OF PHYSICAL EQUIPMENT

Physical equipment possesses value due (1) to use in obtaining oil production, and (2) to sale or disposal of the equipment at the end of its period of usefulness. In addition to these elements of value there is the more or less arbitrary conception of depreciated value.

Definitions

Value in Use.—Value in use is the value of the physical equipment in creating income from the production of oil. This income is the joint result of the oil reserves and of the physical equipment; any allocation of value between these two elements must be arbitrary.

Sales Value.—The physical equipment on a given property consists of (1) equipment essential for obtaining oil, and (2) equipment not essential for obtaining oil. The former includes casing, tubing, sucker rods, etc., in the well; and on the surface, pumping equipment, engines or motors, and in some cases central power plants. The latter includes drilling tools, additional casing, camping outfits, and such equipment as can be removed from the property without interfering with production. The sales or exchange value of physical equipment is the total value derived from the sale, exchange, or disposal of both types of equipment.

Salvage Value.—When an oil property is abandoned, the physical equipment may be sold, used again on a different property by the same owner or discarded as worthless. Salvage value may be defined as any value that can be saved upon abandonment. This value will be reflected by the sales price in the first case, some form of revaluation may be used in the second case, while in the last case there is no value.

Depreciated Value.—Depreciated value or remaining value is the value obtained after subtracting depreciation, the depreciation being determined by some convenient formula. Depreciated value and salvage value seldom coincide; their difference

is fundamental, owing to the specific purpose each is to serve. Salvage value is determined with the purpose of computing the value of physical equipment when used on another property, or what will be the probable monetary return as determined by actual sales of similar goods. Depreciation is determined with the purpose of amortizing the property by the time it has reached the end of its useful life; depreciated value is merely a by-product and is the numerical result obtained by subtracting depreciation from cost. It is not a result to be sought for in itself, and no attempt is made to have it reflect the true worth of the property.

Value in Use

The value of an oil property is primarily dependent upon the income derived from the oil produced; this production is, in turn, dependent upon the oil reserves and the proper equipment and development of the property. When the value of the oil production is determined, an element of value represented by the use of physical equipment is also included, yet one of the most common errors in appraisal is to add to the value of the oil production the total value of the physical equipment. A little reflection will show the absurdity of such a procedure. Can the entire equipment be sold and then production obtained? Both equipment and oil reserves are essential in obtaining production and are so closely related that it is difficult to determine their individual values. If allocation between the value of oil reserves and the value of physical equipment is required, arbitrary formulas may be used to determine the value of the physical equipment, using its cost or replacement cost as a starting point. These formulas are more definitely described in the chapter on "Depreciation."

The value of physical equipment may be determined in accordance with the service which it is capable of yielding. What replacements will be required? What repairs will be needed? How long will the present equipment give efficient service? The cost of replacements and repairs must be considered when estimating costs.

Sales Value

Additional Equipment.—Additional equipment not necessary for the production of oil may be used on other properties or sold. The value of such equipment can be quite readily determined

from its cost and an analysis of appropriate factors. Ordinarily, it is not necessary to apply discount factors to determine the present worth of this equipment, as it is usually sold or used without any great delay.

Salvage Value.—The sales price of a second-hand structure is dependent upon numerous conditions. Those of greatest importance are:

1. Reason for selling.
2. Condition of the structure.
3. Market price of like structures, new.
4. Ease of marketing.

Suspicion.—Suspicion attaches itself to the sale of second-hand goods. The buyer suspects the goods to be worn out, to be obsolete, or to have unknown defects, and wonders why they are offered for sale if they are as valuable as the owner advertises them to be. His suspicion increases if the owner is buying similar goods or materials. Suspicion is greatly allayed if a satisfactory reason can be given for the sale. The attitude of doubting and questioning the value of second-hand structures is responsible for failure to realize more than 50 to 70 per cent of the original cost, even though it may be practically new.

Condition of Equipment.—Defects in casing cannot be readily ascertained until the casing is pulled; if too defective, the casing will part and its removal will be impossible. The condition of the casing will depend largely upon the length of time it has been underground and the chemical effects of underground waters. Equipment above ground is open to inspection, and its condition reflects its exposure to the elements and the care that has been bestowed upon it. The effect on sales price of known defects is obvious. However, old equipment may bring a fair price if it has been well cared for, as it possesses the appearance of new goods.

Market Prices.—Fluctuations in the market price of new equipment greatly affect the sales price of second-hand goods. During periods of intense oil activity, prices of material are high, and materials bought during periods of depression may then be sold at a price in excess of their cost.

Ease of Marketing.—The principal factors affecting the marketability of a structure are preparation for and transportation to market. Cost of preparing underground equipment for market may be prohibitive if the material is in poor condition; casing must

be pulled and pipe lines dug up. Where long hauls over poor roads are combined with excessive freight charges, the cost of transportation to market may exceed the value of the material, as all types of oil field equipment are heavy.

A careful analysis of the foregoing factors is a necessary preliminary to the determination of salvage value. If there is an active market, the value of second-hand goods may be obtained by subtracting the cost of marketing from the prevailing price of similar materials. The determination of salvage value is more difficult if there is no active market for second-hand goods.

Fish's Formula.—The value of used equipment may be required even when no sale is contemplated, as in partnership accounting when one partner leaves the business or a new partner is added, or where equipment is transferred from one property to another. In such cases it may be desirable to apply Fish's Equal Profits Ratio Formula. The formula is based on the following principle: A fair price for a second-hand structure is such as will cause the rate of return on the investment to be the same for the seller as for the buyer. In its simplest form the formula is stated as the following proportion:

Original cost: Present value = Total estimated profit, past and future: Total future profit

In order to solve the proportion for present or salvage value, the original cost must be known, together with past profits and expected future profits.

Summary.—When appraising oil properties two elements of value of the physical equipment may be added to the value of the income from oil production; first, sales value of such equipment not required for obtaining oil; this value, ordinarily, does not need to be discounted to determine present worth; second, salvage value of the equipment used in obtaining the oil; this usually must be discounted to determine its present worth.

CHAPTER VI

COSTS

The oil industry employs vast armies of workers. One army, composed of engineers, drillers, leasemen, lawyers, teamsters, geologists, clerks, accountants, pumpers, superintendents, and executives, all find their employment directly in the extraction of oil. Other armies are required in the supply of raw materials from mines and forests; in their manufacture into casing, drilling tools, pumps, boilers, engines, tubing, drilling cable, rig irons, and small tools; and in the transportation of raw materials to centers of manufacture and the distribution of the finished products to the various oil fields. The expenditures involved, including payment of salaries and wages and costs of material and equipment, are enormous, amounting to hundreds of millions of dollars annually. Each lease or tract must bear its proportionate share of this expenditure.

The royalty owner usually bears little expense; the operator must not only bear all expenses of development, equipment, and operation, but in addition must pay for his interest in the land. Expenses will here be considered from the standpoint of the operator.

COST OF THE LAND

The following elements enter into the cost of the land:

1. Cost of options.
2. Purchase price (when purchased outright).
3. Bonus.
4. Rentals.
5. Royalties.
6. Leasing expense.
7. Legal expense.
8. Land surveys.
9. Exploration costs.
10. Taxes.
11. Interest on investment.

Options.—An option is the right within a specified time to purchase or lease land under certain stipulated terms, time being an essential factor. Options may be granted pending further investigation of the property, or while endeavoring to raise sufficient funds.

Outright Purchase.—Where land is purchased outright there are no payments in the form of bonuses, rentals, or royalties, and possible conflicts between the interests of the owner and the lessee are eliminated. Where land has considerable value for agricultural or other purposes, it usually is leased, but if its chief value is the mineral rights, it is commonly purchased in fee by the operator.

Bonuses.—Bonuses are additional sums paid under the terms of the lease. Where undeveloped lands are of but little value, as in some parts of the Appalachian oil fields, bonuses are seldom paid, the royalty and rentals being considered sufficient compensation to the owner. Bonuses amounting to thousands of dollars per acre may be required where oil lands are valuable, as in Osage County, Oklahoma.

Rentals.—Leases ordinarily require the completion of a well within a specified time or the payment of rentals until production is obtained. Usually the amount of rentals is not great but where properties are held for years prior to their development these amounts may be considerable.

Royalties.—Royalty is a continuous payment to the land owner consisting of a fixed percentage, usually one-sixth or one-eighth, of the oil produced. For purposes of appraising a lease, it is convenient, in most cases, to consider only net production, that is, production after the royalty has been deducted.

Leasing Expense.—The costs of obtaining leases are excessive in remote regions removed from the main lines of travel, where railroad and other transportation facilities are poor; not only is much time and expense required in travel, but the land owners are suspicious, thus causing difficulties in the transaction of business.

Concessions from foreign governments are analogous to leases. It is reported that 15 or more years of effort on the part of American interests were spent in attempting to secure from Turkey the Chester concession in Anatolia.

Legal Expense.—There are always certain legal expenses involved with the transfer of title, such as recording fees, fees

for abstracting, and passing upon abstracts. A clear title is of utmost importance. The number of lawsuits concerning title which arise when oil is discovered on a property is truly remarkable. These disputes are particularly numerous on Indian lands, where the Indians are wards of the Government, and in California and Wyoming on land claimed by the Government.

Land Surveys.—Land surveys are necessary to establish claims of contesting parties when boundaries are in dispute. Upon the discovery of oil in the Red River, a resurvey of the disputed boundary between Texas and Oklahoma became imperative. This incident was quite colorful, involving as it did armed forces, disputes between two states and the Federal Government, as well as between many individuals, and receivership by the United States.

Exploration Costs.—The attempt to reduce expenses by the elimination of geological surveys is likely to be disappointing. The chief impediments to progress in making such surveys are lack of outcrops, wooded country, inaccessibility, and unfavorable climate; rain and cold may reduce efficiency and retard progress, while in the tropics, unsanitary conditions may give rise to disease. The territory surveyed in one day varies from less than 1 square mile to more than one township, depending upon difficulties encountered and accuracy required.

The exploration for oil has largely been restricted to the more favorable areas; the future supply will come more and more from deep formations and from areas where surface indications are lacking. Recently, more attention has been paid to obtaining accurate data concerning the underlying strata. Diamond drilling methods have been applied to petroleum exploration, and core barrels are being used with rotary outfits; the costs of exploration are thereby increased, but total costs reduced. More of this work will be done in the future.

Taxes and Interest.—Taxes are commonly assessed upon land, production, and income. Interest must be paid on money borrowed to purchase, drill, equip, or operate properties. Only such taxes as are assessed against the land and only the interest paid on investment in the land should be included in its cost. Taxes and interest are discussed more fully under "Overhead Expense."

DEVELOPMENT COSTS

In the year 1920, 35,000 wells were drilled in the United States with an estimated cost of $575,000,000, or an average of $16,000 to $17,000 each.[1] The individual cost of wells varies from less than $1,000 to $100,000 and more. In the Gulf Coast fields, wells 3,200 to 4,000 feet deep are reported to have cost $40,000 to $75,000 in 1921; wells 1,500 feet deep drilled near Laredo, Texas, are reported to have cost $8,000 in 1922. At present (1923), it is costing from $85,000 to $150,000 to complete deep wells in the Los Angeles basin, California.[2] Costs of wells vary so greatly that cost data are of little value unless the exact conditions of drilling are given; averages, while interesting, have little practical use.

Factors.—An analysis of the factors affecting costs is a first requisite to the proper use of cost data. The chief factors are:

1. Geological.
   (*a*) Depth of the producing horizon.
   (*b*) Type of the strata to be penetrated.
   (*c*) Presence of water sands.
2. Engineering:
   (*a*) Efficient solution of drilling methods.
   (*b*) Efficient handling of labor.
3. Economic conditions:
   (*a*) Price of material.
   (*b*) Cost of labor.
4. Geographical:
   (*a*) Topographic conditions.
   (*b*) Transportation facilities.
   (*c*) Political condition.
   (*d*) Economic conditions.
   (*e*) Climatic conditions.
5. Size and shape of lease.

Geological Factors

Depth.—Drilling costs for shallow wells vary from $1.50 to $15 a foot, and for deeper wells from $8 to $60 a foot; wells 3,000 feet deep cost 50 per cent more per foot than wells 1,000

[1] Suman, John R.: "Petroleum Production Methods," p. 1.
[2] Stroud, Ben K.: Written communication.

to 2,000 feet deep. In shallow wells, 75 or 100 feet may be drilled in a day under favorable circumstances with cable tools; with rotary tools as much as 750 feet have been reported, while deep tests may average only 10 or 15 feet a day.

Increased cost of drilling with increase in depth is due not only to the consumption of more time and encountering of greater difficulties, but also to the more expensive equipment and material required; heavier tools, more powerful engines, and larger derricks must be employed in drilling deep holes, and heavier casings must be used. Portable drilling machines and rigs, eliminating time and cost of construction of the usual type of derrick, may be employed advantageously in shallow fields where the depth is less than 1,000 feet; in some instances, they have been used for drilling to greater depths.

Character of Strata.—Hard formations are readily penetrated by cable tools, but only with difficulty by rotary tools, while the reverse is true of unconsolidated strata. Where both hard and unconsolidated materials are present, as in certain parts of California, it has been found necessary to employ a combination system, employing both cable and rotary tools. Costs depend upon the character of the strata penetrated and upon the drilling method employed.

Water Sands.—In order to finish with a 6-inch hole at the oil sand it may be necessary to start with a 10- or 12-inch hole, depending upon the number of water sands and number and thickness of caving formations present. Extreme conditions are found in the Russian oil fields, where it is customary to start with a 40-inch hole, and in the eastern United States, where a 2,000-foot hole may be drilled with the insertion of but little casing. Frequently, part of the casing may be recovered. Drilling costs vary with the diameter of the hole, and casing costs with the amount and size of casing required.

Engineering Factors

The purpose of engineering is to increase profits, either by decreasing costs, increasing output, or by both. Costs will depend upon the engineering ability displayed in selecting the best methods and their efficient execution.

Drilling Methods.—Costs are greatly reduced by restricting the use of rotary and of cable tools to that type of strata to

which each is best adapted. McLaughlin[1] considers that a saving of $1.50 per foot was effected by the use of the rotary system in the Coyote Hills field, California. The cost per foot was $8 as against $9.50 in the Puente Hills fields, California, where the standard (or cable), tools were employed, geological conditions being the same. In other instances, much greater savings may be effected by the use of the proper drilling method. The greater speed of drilling with rotary tools makes this method particularly advantageous in drilling offset wells; while the possibilities of passing through an oil sand without recognizing it as such, makes it less desirable for drilling wildcat wells.

Power.—It is impossible to make general statements concerning the cheapest form of power to use in drilling. It has been estimated by engineers of the Empire Gas and Fuel Company that $3,655.20 was saved by the use of electricity rather than steam in the drilling of the Stokes No. 27 well in the Eldorado field, Kansas. On the other hand, the flexibility of steam power may more than compensate for any saving in cost.

Fishing Jobs.—Fishing jobs are expensive and their occurrence, while partly dependent upon geological conditions, may be greatly increased by carelessness, especially in the hurry of completing a well. When using the cable system, lost tools may be due to worn cables, poor attachment of tools to the drilling cable, and paying out either too much or too little cable, causing undue strains and fatigue of iron by excessive jarring, with consequent breaking of tools at some point. In the use of rotary tools, fishing jobs may be due to dropping the drill pipe into the hole, but it is more commonly due to twisting the drill pipe off, either by too rapid drilling, when in hard formation, or by the continued use of the drill pipe after the point of fatigue has been reached; the possibilities of these "twist offs" are greatly reduced by the use of seamless drill pipe.

Efficiency of Labor.—The cost of labor is an important element in drilling, and is dependent largely upon the time consumed. Where geological conditions are uniform, speed of drilling, ordinarily, depends upon the skill and industry of the workmen, their efficient management, and the prevention of time lost waiting for materials or tools. In writing of conditions in certain

[1] McLaughlin, R. P.: "Petroleum Industry of California," State Min. Bur., *Bull.* 69.

California fields, McLaughlin[1] states that rivalry between drillers increased the rate of drilling from 12 to 25 feet a day, standard tools being used in both instances.

Economic Conditions

The economic factors controlling the price of petroleum have already been discussed; similar factors control the rate of wages and price of material. In general, prices of petroleum and costs of labor and material show similar fluctuations—both are low during periods of depression and high during periods of activity, although there are numerous exceptions. Wood and steel are the chief materials used and any changes affecting the prices of these materials are of great significance to the oil industry.

Geographical Factors

Oil wells are drilled in mountains, fertile plains, deserts, semi-desert countries, and even in bodies of water. Plains present the fewest difficulties and hence involve the least expense. Unusual difficulties and additional items of expense are involved when drilling in bodies of water, of which Caddo Lake, Louisiana, Red River, along the Texas-Oklahoma boundary, Cimarron River, Oklahoma, and the Pacific Ocean near Los Angeles, California, are examples. In mountainous countries wildcat wells are usually drilled in the valley bottoms to reduce costs. When drilling in deserts, supplies, ordinarily obtained close at hand in fertile countries, may have to be hauled long distances; sufficient water for men, animals, and for drilling purposes must be supplied. The occurrence of droughts has greatly curtailed drilling activity in many parts of the Mid-Continent field.

Transportation costs are high where bad roads and long hauls are involved. The Frantz well, in the Cat Creek pool in Montana, is reported to have cost five times as much as it would have cost under favorable circumstances.

Climatic, political, economic, and transportation conditions render development in many foreign oil fields unusually difficult.

[1] McLaughlin, R. P.: "Petroleum Industry of California," State Min. Bur., *Bull.* 69.

Neither extreme cold, as in the Fort Norman field, Canada, nor extreme heat, as in the tropics, are conducive to efficiency. The labor problem may become acute in tropical development; it is difficult to secure efficient laborers and well-trained engineers. Thompson reports that at one time 70 per cent of his staff and labor force were incapacitated by fever.[1] Difficulty in obtaining concessions, political corruption, high taxes, and lack of stable government often work hardships upon operators in foreign fields. It has been estimated that for every dollar spent in the development of oil in the United States, an expenditure of $10 is required to accomplish the same results in foreign development.

Size and Shape of Property

Leases vary in size from a few acres to thousands of acres. Where section lines have been established, most leases have north-south and east-west boundaries, but along rivers, in mountains, and where the country has not been subdivided into sections, as in the major portion of the Appalachian field, the boundaries are irregular. The lease may be elongated, compact, or irregular in shape.

The operator is obliged to protect the interests of the lessor by drilling offset wells along the boundaries of the lease as occasion requires. The more irregular the shape of the lease, the greater the expense incurred under the obligation. If the lease is very irregular, this obligation may require so great an expenditure as seriously to affect the value of the property.

COST OF EQUIPMENT

Wells frequently flow naturally when completed, but the installation of adequate and efficient pumping equipment can seldom be long delayed. This equipment consists of tubing, valves, sucker rods, and some source of power, either individual motors or central power with shackle lines, depending upon field conditions. Its cost, including installation, varies from a few hundred dollars to several thousand dollars a well. Transportation charges are an integral part of the cost of installation and include freight rates, teaming, repairs on roads, which are soon destroyed by

[1] Thompson, A. Beeby: "Oil Field Development," p. 57.

the hauling of heavy oil well equipment, and in some instances the cost of constructing new roads.

Electrical Power.—Electrical power for pumping has been applied extensively in the last few years. Motors for wells cost approximately $300 to $600, to which must be added the cost of installation, field wiring, poles, etc. Electricity may be purchased in some fields from a power company or it may be generated at a central power plant. "A plant designed for 900 kilowatt duty will cost (1920) about $272 per kilowatt installed for the Diesel engine drive, and $163 per kilowatt installed for the steam turbine driven installation."[1]

Method of Extraction.—Increased production frequently results from flooding, use of compressed air, or use of vacuum; these methods entail increased expenditures, either in installation or operation. In proportion to the added costs the results obtained are probably least in the employment of vacuum pumping.

The pre-war cost of installing compressed air averaged about $100 a well. At least 80 per cent of this cost is for equipment, about 55 per cent for the compression plant, and the remaining 25 per cent for air lines. The use of compressed air commonly increases operating costs 25 to 50 per cent, although in a few instances they have been doubled.[2]

In the Bradford field, Pennsylvania, flooding the oil sand with water is extensively employed. A spacing at least as close as 100 feet between wells is desirable in the direction of advance of the flood, as the water usually advances only 50 or 100 feet a year or even less. When preparing for a flood, sufficient wells are commonly drilled to give the desired spacing; the number of wells to be drilled consequently depends upon the original spacing.

OPERATING COSTS

Operating costs are those costs incurred after the well or lease is developed and equipped, for the most part they are recurrent in nature and are here classified into field expense, overhead, and contingencies. The following analysis shows the items sometimes included under operating expense, and their proportionate amounts. Lifting cost has been confused sometimes with

[1] Suman, John R.: "Petroleum Production Methods," p. 388.

[2] Lewis, J. O.: "Methods for Increasing the Recovery from Oil Sands."

operating cost and considered as its equivalent, but here it constitutes less than half of the total expenditures.

COST OF OPERATING 1,932 WELLS IN OSAGE COUNTY, OKLAHOMA[1]

	Per cent of total	Amount per barrel lifted	Amount per well per day
Lifting	44	$0.41	$1.58
Overhead	14	0.13	0.52
General	16	0.15	0.61
Depreciation	26	0.24	0.92
Total	100	$0.93	$3.63

[1] Data compiled from information published in the *Oil and Gas Journal*, Sept. 30, 1921.

FIELD EXPENSE

Many items enter into field expense: pumping, repairing of wells, cleaning, maintenance, cost of fuel, superintendence, etc. Their significance varies greatly from field to field, and their proportionate amounts for one property containing 338 wells in the Kern River field, California, are shown in the following table.

OPERATING COSTS KERN RIVER FIELD, CALIFORNIA[1]

	AMOUNT PER WELL PER MONTH
Pumping	$ 36.01
Repairing	48.75
Collecting and cleaning	10.41
General maintenance	1.55
Superintendence	12.60
Miscellaneous	9.02
Fuel	25.00
Total	$143.33
Total per well per day	$ 4.78

[1] MCLAUGHLIN, R. P.: "The Petroleum Industry of California," State Min. Bur., *Bull.* 69, p. 262.

The attention required in operating individual properties is so variable that it is impossible to give average figures which would have any meaning. A few wells may demand the entire attention of an experienced operator, while, on the contrary, it may be possible to employ a farmer a few hours each day to

supervise the pumping of 20 or 30 wells. McLaughlin[1] states that in California the operating costs for wells using individual powers vary from 90 cents to more than $5 or even $10 per well per day.

Central Powers.—The use of central powers and shackle lines reduces operating costs considerably. In the Puenta Hills field, California, the operating cost of one group of wells using individual powers was $2.34 per well per day, as contrasted with 16 cents per well per day on a second group using central powers.[1] When central powers are used, the cost of operation depends largely upon the number of wells that can be connected efficiently to one power. Level ground, proximity of wells, and shallow depths permit a large number of wells to be so connected; under proper conditions one power may pump 35 or more wells. However, the necessity of frequent pulling and cleaning the wells, great power requirements, loss of power in transmission, or the inability to obtain the right to lay shackle lines, as in town lots or through particularly valuable land, may necessitate the employment of individual powers.

Fuel and Power.—Electric motors, steam, and gasoline engines are used in oil field pumping; coal, oil, gas, or wood may be used as fuel. Because of variations from field to field it is impossible to make general statements concerning the relative cost of each of these methods, but where there is a supply of cheap gas, no other fuel can compete with it. Lately there has been an increase in the use of electrical power, and a saving probably would be effected by its further use, as it is well adapted to many localities where it is not now employed.

Repairs.—Repairs are largely due to the entrance of sand into the wells, wearing out parts of the pumps. Sand troubles are at a minimum when the sand is hard and stands up well, and where the well has been properly cased and cleaned when completed, and a liberal pocket drilled below the sand. On the contrary, when the sand is loose and unconsolidated, especially if the foregoing precautions have not been observed, the wear of the cups is so severe as to cause a real problem in the maintenance of wells; in some fields it is necessary to replace cups every day. Strainers

[1] McLaughlin, R. P.: "The Petroleum Industry of California," State Min. Bur., *Bull.* 69.

have been used to prevent this wear, but it has been found that they frequently cause an accumulation of sand about the opening, clogging the well and interfering with production. The maximum production of oil is frequently obtained only with the maximum amount of sand.

Overhead

Administration.—Any reduction in the cost of administration, including the maintenance of records and reports required for executive guidance, if it interferes with efficiency, is not economy, as the final result will be increased expenditures. Small operators frequently drill their properties without geological advice, and their accounting and financial records are often in poor condition. The administration of the larger companies is usually much more efficient. However, one long-established company, the records of which the author had occasion to inspect, did not have a complete record of even the dry holes it had drilled. Inasmuch as the company had carried on active operations in a dozen counties, over a period of 30 or 40 years, it is not at all improbable that it drilled a second test hole on a property already condemned by its own dry holes.

Taxes.—Provision must be made for property taxes, production or severance taxes, and income taxes. Property taxes are usually assessed by the state, county, and other local bodies; their amount is dependent upon the local laws. The principle of the production or severance tax is simple, the amount of the tax being a fixed percentage of the oil produced, or its monetary equivalent. These taxes are the modern representative of the historical idea of royalties, which were payments of a fixed percentage of the product to the crown.

Income taxes are levied by the Federal Government; assessments are made only if the property is on a profit-making basis. They assume importance in any venture involving great risk. The acceptance of great risk should be compensated by great profit if the venture is successful, and when high taxes are combined with progressive features, they act as a deterrent toward the acceptance of great risk, as much of the reward is thus eliminated.

Interest.—The amount of capital borrowed by an oil company determines the interest charges it must meet and affects the value of the company and its stock. Obviously, the value

of the oil lands is unaffected by the method of financing, whether the company is investing its own or borrowed capital. In the valuation of oil lands, interest charges must be considered with respect to total investment rather than that portion represented by borrowed capital. Further treatment of this subject will be found in the next chapter.

Contingencies

Wind.—The occurrence of contingencies is likely to be underestimated. Serious damage may be caused by wind, fire, flood, lightning, and accidents in shooting wells. Open prairies located in the paths of tornadoes are the scenes of much damage from winds; these conditions prevail in Kansas where winds are proverbial. The constant exposure of derricks used for pumping renders them particularly susceptible to damage from wind; this danger is materially lessened if the derricks are used for drilling purposes only, as they are then exposed for a much shorter period of time. One severe wind in the fall of 1919 caused considerable damage in the Texas coastal field, demolishing a dozen derricks in the Goose Creek field, a similar number in the Humble pool, eleven at West Columbia, a few scattered derricks in the Sour Lake, Hull, and Saratoga pools, and a number of derricks of wildcat wells.

Fires.—All enterprises must make allowance for loss from fire, but this is particularly true in the oil industry because of the inflammable character of the product. Fires may burn for weeks or months before being extinguished, causing the loss of immense quantities of oil from the burning well, and at the same time are a constant menace to surrounding wells. Prairie or forest fires, which occur most frequently in the hot dry summer months, the lighting of matches or smoking too near a well, lightning, and the striking of stones against each other or against the casing as they are blown from the well when the well "comes in"—all contribute their quota of fires. High derricks, especially if wet or of steel, afford a splendid target for lightning; tanks, though not so high, are more commonly made of steel and cognizance should be taken of their power to attract electricity.

Flood.—Oil sands may be flooded by surface waters or from water sands; the entrance of water into one well may flood the oil sand and thus affect an entire pool. Derricks in bodies of water, as shallow lakes, rivers, and even parts of oceans, are

picturesque, but can hardly be considered safe. Properties which otherwise were quite valuable have been abandoned, due to the recurrent expense caused by floods.

"Shooting Wells."—In many fields it is the usual practice to "shoot the well" by exploding a charge of nitroglycerin in the drill hole at the oil horizon for the purpose of increasing the flow of oil; if the nitroglycerin explodes prematurely the casing or derrick may be seriously damaged and even demolished.

Fishing jobs have already been discussed. Furthermore, there are many other possible accidents not here enumerated for which allowance must be made.

METHODS OF ESTIMATING COSTS

Correct valuations require the inclusion of all proper items of cost, their correct estimation, classification, and application. Several methods are commonly employed for estimating costs, some being particularly adapted for speed and others for accuracy. The methods of total costs, of total unit costs, and of analysis and unit costs are here discussed.

Total Costs.—Estimates of the total cost of a completed well are frequently given in a lump sum. If the cost of the first well in a new field was $40,000, the second well might be estimated to cost $30,000, it being assumed that 25 per cent of the cost of the first well could be saved. On the basis that a 2,000-foot well cost $30,000 and a 3,000-foot well cost $60,000, it might be estimated that a 2,500-foot well would cost $45,000. When a large number of wells have been drilled in a given field the average cost may be used as the basis for further estimates. These examples will illustrate the simplicity of the method of total costs.

Total Unit Costs.—Operating costs are usually expressed in terms of some convenient unit, either a unit of time, as yearly cost per well, or as a unit of output, as cost per barrel produced. Costs expressed in barrels of production are useful when comparing cost with income, as the barrel is the unit used in stating the price of oil.

For purposes of valuation it is desirable to express operating costs in such a unit that it will be nearly constant throughout the life of the well; for this reason yearly costs may advisedly be used when considering small wells. As production declines, total operating cost also declines, but less rapidly, resulting in an

increase in the cost per barrel. This principle is well illustrated by the following analysis of the operating cost of 1,932 wells in the Osage Nation, Oklahoma:[1]

Class	Average production per well per day, barrels	Cost per well per day	Cost per barrel
10–5 barrels.....	6.58	$4.97	$0.73
5–4 barrels.....	4.57	4.23	0.93
4–3 barrels.....	3.35	3.41	1.02
3–2 barrels.....	2.37	3.30	1.39
2 barrels and under	1.31	2.90	2.21
Range in costs.....	....	65%	203%

The total range in the cost per barrel is three times as great as the range in cost per well per day. From this fact it may be inferred that, in general, costs are more nearly constant when a time unit is employed in their computation than when costs per barrel are used.

Total costs and unit costs are very useful in checking detailed estimates, or when need is felt for rapidity at the sacrifice of accuracy; although their application is simple, they ignore the complexity of factors which control such costs.

Method of Analysis and Unit Costs.—The method of analysis and unit costs consists of estimating each item of expense and applying unit costs wherever possible. A list of the material required for a definite structure, as a derrick, is given by many of the supply houses. Knowing current prices, the cost of the material can readily be computed, and the effect of variations in market price or in details of construction can be applied with but little difficulty. Cost of labor may be computed either from rates of wages and time required for the accomplishment of certain tasks, or it may be computed on the basis of work performed, as cost per foot of hole drilled. The cost of drilling through a particularly resistant strata may be computed separately. A knowledge of the occurrence of water sands, depths at which casing is to be set, and the number of feet of the various sizes of casing required will furnish the basis for determining casing costs.

[1] Compiled from data published in the *Oil and Gas Journal*, Sept. 30, 1921.

The method of analysis and unit costs involves all the technical knowledge available, including the proper evaluation of the factors already discussed. With a large number of items estimated independently, certain items will be overestimated and others underestimated; a given error is likely to be compensated by an error in an opposite sense. If estimates are continually being made, a list may be prepared of all items to be included; any omission in the list may be corrected as soon as discovered. The actual cost of each item of completed work should be compared with the original estimates. Future estimates can then be modified in accordance with corrections discovered.

Estimating charts are useful adjuncts in any one of these methods, although the method of analysis and unit costs permits of its greater application, because of the larger number of elements involved to which graphical expression can be applied.

CLASSIFICATION OF COSTS

Many classifications of cost are required in appraisals, different classifications being required for different purposes; expenditures have been classified as (1) capital and expense, (2) contingent and regular, and (3) direct and indirect.

Capital and Expense

Two characteristics distinguish capital expenditures from operating expense. Expense is recurrent in nature and adds little to the value of the assets, while capital expenditures are not recurrent and add materially to the value of the assets. In the computation of profit or loss for a given period, expense is deducted at once; but the cost of capital items is deducted throughout the life of the property through a series of depletion and depreciation deductions, the total of which cannot exceed the cost of the property or value as of some basic date.

Taxation.—The classification into capital and expense is of prime significance in connection with the Federal income tax, and must be recognized by engineers when making valuations and computing depletion for taxation purposes. Capital items, under Federal income tax regulations, include the cost of the land and physical equipment and may include the cost of development.

Land.—The following definitions are modified from those given in the "Manual for the Oil and Gas Industry."

[The cost of the land] includes all amounts (in cash or its equivalent) paid for and incident to the establishment of title and acquisition of the lease or fee, as the case may be, such as—

Purchase price of lease or fee. . . .

Salaries or commissions paid to brokers or agents.

Fees to geologists, attorneys, surveyors, etc., for examination and defense of title, establishing boundaries, etc., state and county fees for recording and legalizing transfers, and all other payments made in acquiring and establishing title to the properties.

Physical Equipment.—[Physical equipment is] all equipment having an inventory or salvage value and subject to removal from the property, such as buildings, bridges, and power plants; derricks, casing, drilling equipment (cable and rotary), and pumping equipment, including engines, boilers, tubing and rods; flow lines, and connections on wells, tanks attached to wells, and other tankage of steel, wood, or concrete; cleaning and pulling equipment; salt water equipment; refineries, treating and reducing plants, including casing-head gas plants; telegraph and telephone lines, pipe lines and tank cars, and all other equipment used in the production, reduction, conservation, or transportation of oil and gas or their products.

Development.—Cost of development comprises all payments made for and incident to the drilling of wells, such as cost of . . . geological and other surveys made subsequent to acquisition, roads, water supplies, hauling, wages, drilling, shooting, overhead charges (incident to drilling of wells), and fuel.

Large oil companies annually spend immense sums for purposes of development; hence, many accountants consider it a recurrent expenditure and classify it as an item of expense. The Federal Government recognizes both classifications of development and permits the taxpayer to exercise an option of charging development to either expense or capital, but "election once made under this option is final and will control the returns for all subsequent years." The cost (or value) of the land and of development, if charged to capital, forms the basis upon which depletion is computed; the cost of physical equipment forms the basis for computing depreciation.

Expense.—Expense includes all amounts paid out (exclusive of amounts paid for physical property and development charged to Capital Sum) incident to the development and operation of producing properties

and the preparation of their product for market, such as costs of pumping, cleaning, reshooting (including cost of torpedoes), gaging, storing, treating, reducing, repairs, and maintenance, transporting, refining, conserving, marketing, overhead expense, insurance, etc.

Valuation.—When valuing oil lands the individual property is the logical unit, and as far as it is concerned, drilling is an expenditure belonging to the period of development and should be regarded as a capital investment. If the accountant charges drilling and similar expenditures to the capital account, there is little need for the valuation engineer to revise the classification. The chief inquiry of the engineer concerning the classification of any item of expense should be, "Is this expenditure restricted to the initial period of development or will it recur continually throughout the life of the property?" When making appraisals a continuous allowance must be made for recurrent expenditures, while initial expenditures are deducted at once. The difference in viewpoint of the accountant and engineer should be understood; the accountant may regard the cost of development either as an item of expense or as a capital expenditure, while the engineer when valuing oil lands regards the development expense as an initial rather than recurrent expenditure. The two classifications, capital and expense, and initial and recurrent, are very similar, and the formal introduction of the latter classification will usually not be necessary.

Contingent and Regular

Most expenditures are regular in their occurrence; contingent expenditures are those the occurrence of which is uncertain. Fishing jobs, damage by storms, the drilling of dry holes, and payments "out of oil," effective only as production is obtained, are examples of contingent expenditures. They require the determination of the probability of their recurrence, as well as an estimation of their cost; regular expenditures involve only the latter determination.

Dry Hole Hazard.—The possibility of drilling dry holes seriously reduces the value of oil lands; the value of the leasehold is reduced most and that of the royalty interest least. Assume that the cost of drilling a hole is $60,000, and that the average value of a productive well is $100,000; if there were no dry hole

hazard the value of the location would be $40,000. Assume that the past history indicates one hole in three will be dry; what then is the value of the location? From three locations it will be assumed that two producing wells will be obtained, with a total value of $200,000; in obtaining two wells one dry hole will on the average be drilled, or a total of three holes at an expense of (3 × $60,000 =) $180,000. Subtracting the drilling cost of three holes ($180,000) from the value of two producing wells ($200,000), the value of the three locations, $20,000, is obtained; the value of one location is $6,666.67. A dry hole hazard of 1 in 3 reduces value in this case from $40,000 to $6,666.67, or 83⅓ per cent.

If the value of a completed well to the royalty owner were $40,000, the value of a location would be $40,000, provided there were no dry hole hazard, since there is no drilling cost. Assume a dry hole hazard of 1 in 3. From three locations two producing wells will be obtained with a total value of (2 × $40,000 =) $80,000, which is also the value of the three locations, no expenditure being required of the royalty owner. The value of one location is $26,666.67, as contrasted with a value of $40,000 where there is no dry hole hazard. Assuming that a property is sufficiently valuable to guarantee its development, a dry hole hazard of 1 in 3 reduces the value of the royalty interest only 33⅓ per cent, much greater reductions occur in the case of the working interests as shown by the previous example. Wherever a dry hole hazard is sufficiently great to prevent the development of the property, neither the working interest nor royalty interest has any value.

Payments in Oil.—Not infrequently payments of a bonus or of the purchase price are made at least partially "in oil." Until the entire obligation of a contract has been met, its fulfilment may require the payment of half or any other portion of the value of the oil produced, or even the entire value.

A lease calls for a contingent payment of $100,000 out of the first oil. Assume that the history of surrounding leases indicates the chances for obtaining a dry hole and abandoning the lease are 30 per cent, the chances for producing 25,000, 50,000, and 75,000 barrels of oil are each 10 per cent, and for producing 100,000 barrels of oil or more are 40 per cent. Oil is selling at $1 a barrel. Assuming the price of oil to remain constant, what is the value of such a clause to the lessor and what is the probable

cost to the lessee from such a contract? The probabilities for the payment of this sum are given below:

Total production obtained, barrels	Sum paid	Probabilities, per cent	Value
None	None	30	None
25,000	$ 25,000	10	$ 2,500
50,000	50,000	10	5,000
75,000	75,000	10	7,500
100,000, or more	100,000	40	40,000
			$55,000

The total value of such a clause to the lessor and the prospective cost to the lessee are $55,000. There is one chance in 10 of paying $25,000; the actuarial worth of this contingency is $2,500, which should be discounted to determine present worth. The same principle applies to each of the other possibilities.

Accidents.—It is difficult but not impossible to make proper allowance for losses resulting from the various types of accidents. A number of these contingencies have been studied by insurance companies. These insurance rates against given hazards form a good basis upon which to calculate the required allowance.

Direct and Indirect Costs

An operator can afford to pay more for an adjacent property than for a property necessitating separate operation; the operation of several adjoining properties under one management decreases cost of superintendence, administration, and lifting, and decreases the number of offset wells. An official of one of the eastern oil companies, after making a valuation of their properties, stated that if they had been operated separately they would have been essentially valueless.

Based upon the savings effected by joint operation, costs may be divided into two classes: (1) the direct or variable costs, that is, those items of cost which represent the extra expenditures caused by the addition of a well to a lease or of a lease to a group of leases, as extra fuel, additional repairs, etc.; (2) indirect or constant costs, which include those expenditures

that are not affected by any of these additions, as a large share of the cost of superintendence. Conversely, only the direct costs of a well or lease are decreased by abandonment.

Assume that the monthly operating cost of a lease having 10 wells is $400, and that $25 will be saved by the abandonment of a given well. The profitable operation of the individual wells and of the tract demands: (1) that the income from each well shall be in excess of the direct costs of operation, which in this case are $25 a month; (2) that the income from all wells shall be in excess of both the direct and indirect costs of operation, which in this case are $400 a month.

The above principles must be recognized when considering the abandonment of a well or lease or when accurately computing the economic limit. The division of expenditures into direct and indirect costs varies with the point of view, whether considering individual wells in their relation to a lease, individual leases in relation to a group of leases, or any other unit with respect to a larger unit of which it is a part.

CHAPTER VII

INTEREST

Business ventures are expected to return not only the original sum invested but, in addition, interest as payment for the use of capital. The rate of interest has been classified into two elements, cumulative and remunerative. The cumulative rate is that rate required to attract capital in even the safest investments; it is the interest offered to induce the accumulation of savings and is reflected in the return given on Government bonds and by banks on savings accounts and time deposits. When an element of risk is involved, capital expects to be remunerated for this risk, if the enterprise is successful, this additional amount of interest is called the remunerative rate.

Determination of Interest Rate

Considerable discussion has arisen with respect to the interest required to induce capital to invest in mining ventures, much of which is applicable to investment in oil properties. James R. Finley, who made a valuation of the iron mines of Michigan in 1911 for taxation purposes, made no allowance for remunerative interest, using only a 5 per cent rate in his valuations. His contentions are as follows:[1]

> It has been urged that money employed in mining should be allowed a high rate of interest because of the extraordinary uncertainties of the business. While I do not wish to dismiss this subject cavalierly, it seems to me that about all there is to say on this point is that a valuation is logical only on the assumption that the factors used in making it are correct. If such factors are judiciously taken they are as likely to err on one side as on the other . . . as likely to exceed as to fall short; consequently, there is no need of counting on any further doubts than such as are inherent in all human enterprises. I have generally assumed

[1] Finley, James R.: "Valuation of Iron Mines," *Trans.* Am. Inst. Min. Eng., vol. 45, p. 294.

that 5 per cent was a normal interest or discount rate. If that is so, it is a fair figure to use in all mine valuations, which should be nothing but a candid inquiry into the present value of expected profits.

The use of a 5 per cent interest rate caused much discussion. Mr. Finley's critics emphasized the difficulty of allowing for all contingencies, and cited higher rates of return on safer types of investment.

The enormous risk involved and the necessity of offering great inducements in order to attract investment in oil properties have been emphasized and advanced as an argument for using a high rate of interest when determining the present value of future expected earnings. Provision for all contingencies would necessitate the use of an excessively high interest rate—rates as high as 30 per cent have been suggested. An indiscriminate application of high interest rates would seriously affect the value of slowly declining properties, where the production is distributed over a number of years; while the value of properties where the bulk of oil is extracted within a few months would be but slightly affected. Furthermore, this procedure would obscure the individual elements involved in risk.

An adequate allowance for risk should be made when computing each of the factors entering into an appraisal and only those elements of risk for which specific allowance cannot be made or which are likely to be overlooked should be considered in the allowance for remunerative interest. While no one rate can be applied indiscriminately, 10 per cent is suggested as a fair return after due allowance has been made for known risks.

Application of Interest Rate

Interest Method.—Interest may be computed on the proposed purchase price; this interest is first deducted from future expected income and the remainder then applied to the reduction of the investment in the property, very much the same as when making payments on a house purchased on the instalment plan. A property should not only meet all operating expense, and return the amount of the original investment but also provide a sufficient allowance for interest and profit.

Annual Discount Factor.—Payments due at any future date are discounted to determine their present cash value. Ordinarily, the income from oil properties is distributed over a period of years and is received in monthly payments. Each of

these payments may be discounted to determine its present worth, but the computations are greatly simplified by considering all the payments for a year as a single payment received in the middle of the year, and applying discount accordingly. In the application of this method, the income for each year is estimated separately, and the first year's income is assumed to be received at the end of 6 months, and the second year's income at the end of 18 months. Tables based upon various interest rates are submitted in the Appendix, showing the value of $1 received in the middle of any future year, that is, ½, 1½, 2½, etc. years hence, or, expressed in mathematical terms, $(n - \frac{1}{2})$ or $\frac{2n-1}{2}$ years after a given date, n representing any whole number.

The income from salvage is usually received in one lump sum at the time the property is abandoned. Commonly, the time before abandonment is estimated as an even number of years, and the income from salvage discounted accordingly. Tables are given in the Apppendix showing the value of $1 received at the end of any future year, that is, 1, 2, 3, etc. years hence, or, expressed in mathematical terms, n years after a given date.

In an appraisal, the proper discount factors are applied to each year's expected income, and the discounted amounts of the income for each year, throughout the productive life of the property, are added together to determine the total estimated value. The application of discount to reduce future income to present worth has a very wide application in the valuation of oil properties.

Single Discount Factor.—The work involved in the application of discount factors to determine present worth would be greatly reduced if a single discount factor could be used instead of applying separate discount factors to each year's income. Tables of these discount factors are readily prepared for different rates of decline, assuming these rates to remain constant throughout the life of the property. The following table is based upon the foregoing assumption but it can only be used for approximations and illustrative purposes as the conditions assumed are not ordinarily realized. In this table income is assumed to decline at the same rate as production; discount factors are based upon an interest rate of 10 per cent compounded semi-annually and applied as if a year's income were received in the middle of the year.

DISCOUNT FACTORS FOR VARIOUS RATES OF DECLINE AND VARIOUS LENGTHS OF LIFE OF PROPERTY

Life of property		Rate of decline, per cent							
		5	10	15	20	25	30	40	50
5 years	[1]	.80	.81	.82	.82	.83	.84	.86	.88
	[2]	.20	.19	.18	.18	.17	.16	.14	.12
10 years	[1]	.66	.69	.72	.75	.77	.80	.84	.87
	[2]	.34	.31	.28	.25	.23	.20	.16	.13
15 years	[1]	.57	.63	.67	.72	.75	.79	.84	.87
	[2]	.43	.37	.33	.28	.25	.21	.16	.13
20 years	[1]	.51	.58	.65	.70	.75	.78	.84	.87
	[2]	.49	.42	.35	.30	.25	.22	.16	.13
Infinite	[1]	.34	.52	.62	.70	.74	.78	.84	.87
	[2]	.66	.48	.38	.30	.26	.22	.16	.13

[1] The first line in each of the above groups indicates the ratio between the present worth of a future income and the total amount of the income.

[2] The second line in each of the above groups indicates the reduction in value due to the application of discount factors.

If income declines 5 per cent annually, the present value of a total income of $100,000 distributed over 5 years is $100,000 × 0.80 = $80,000; if this amount had been distributed over 20 years the present value would be $51,000; the reduction in value in the two cases is 20 and 49 per cent respectively. Greater reductions in value occur with longer life, but the total reduction on the basis of a 5 per cent decline cannot exceed 66 per cent, regardless of the length of life of the property. If income declines 50 per cent annually, the reduction in value due to the determination of present worth cannot exceed 13 per cent.

Similar tables based on a given decline curve may be prepared and applied to a group of properties whose production conforms to this curve; but ordinarily the work involved in their preparation is greater than their value.

Annuities.—Calculations are greatly simplified when annual income or expense is constant for a period of years and considered as an annuity. Instead of applying the proper discount factor to each annual amount, the discount factors may be added and one factor applied. The relation between discounting a

future income or expenditure annually and the annuity method of capitalization may be seen from the following example. Assume $10,000 as the annual income for 10 years, the first payment to be made 6 months hence, the discount factors being based upon an interest rate of 10 per cent.

DISCOUNT METHOD

Year	Annual income	Discount factor	Present worth
1	$ 10,000.00	0.952	$ 9,520.00
2	10,000.00	0.864	8,640.00
3	10,000.00	0.784	7,840.00
4	10,000.00	0.711	7,110.00
5	10,000.00	0.645	6,450.00
6	10,000.00	0.585	5,850.00
7	10,000.00	0.530	5,300.00
8	10,000.00	0.481	4,810.00
9	10,000.00	0.436	4,360.00
10	10,000.00	0.396	3,960.00
Total	$100,000.00	6.384	$63,840.00

ANNUITY METHOD

Years	Factor	Annual income	Present worth
10	6.384	$10,000.00	$63,840.00

In the foregoing example, the factor applied under the annuity method is the sum of all discount factors applied under the discount method.

The annuity method can be applied most frequently in connection with the capitalization of the annual operating expense, although there are cases when it is applicable to the capitalization of income.

Perpetual Annuities.—Certain properties in the Appalachian field have had a nearly constant production for the last 5 or 10 years or even longer, and it may reasonably be expected that the production of many of these properties will remain nearly constant for at least an equal length of time in the future. There

is but slight difference between the value of an annuity for 20 years and the value of a perpetual annuity of equal annual amount, if both are discounted at the rate of 10 per cent annually. The values of perpetual annuities can readily be computed and may serve as a useful approximation to be used in the valuation of properties of this type. The value of a perpetual annuity is determined by multiplying 1 year's income by a given factor. This factor is obtained by dividing 100 by the annual rate of interest assumed to be earned. If this rate is 5 per cent, the factor to be used is 100 divided by 5, or 20; the annuity is worth 20 times 1 year's net income. If the interest rate is 20 per cent, the annuity would be worth 5 years' income.

"Rule of 72."—In the absence of discount and interest tables, certain approximations concerning the influence of interest or discount may be determined by the "rule of 72." The rule for determining the rate of interest r or the number of years n required for money to double itself is expressed in the following formula:

$$r \times n = 72$$

If r is given, n can be found, and, conversely, if n is given, r can be found. Suppose we wish to find the number of years required for money to double itself at 8 per cent. Divide 72 by 8 and the result is 9. It will take approximately 9 years for money at 8 per cent to double itself; that is, $1 placed at 8 per cent interest will in 9 years amount (with interest) to approximately $2. Conversely, the present value of $1 due 9 years hence is only 50 cents, if discounted at 8 per cent annually. Assume that $100 is due n years hence, and that a 10 per cent discount factor is to be applied annually. Determine n, if the present value is only $50. Seventy-two divided by 10 is 7.2. The answer is 7.2 years; the $100 will be due 7.2 years hence.

CHAPTER VIII

DEPLETION AND DEPRECIATION

There are many ways in which the value of an oil property is lessened. This loss in value may be sudden, as when due to a flood or tornado, or gradual, as through depletion and depreciation.

Agencies Which Decrease the Value of Oil Properties

A. Agencies affecting physical property—depreciation:
  1. Ordinary wear and tear:
    a. Physical wear:
      x. Vibration.
      y. Abrasion.
      z. Overheating.
    b. Chemical deterioration:
      x. Rust.
      y. Corrosion.
      z. Electrolysis.
    c. Biological.
  2. Functional depreciation:
    a. Obsolescence.
    b. Inadequacy.
  3. Accidents:
    a. Losses due to defective material or to negligence.
    b. Losses due to the elements:
      v. Fire.
      w. Lightning.
      x. Wind.
      y. Floods.
      z. Freezing.

B. Agencies affecting oil reserves—depletion:
  1. Actual extraction of oil from the reservoir.
  2. Factors affecting the amount of recoverable reserves:
    a. Geological:
      w. Original content of recoverable oil in reservoir.
      x. Loss of gas pressure.
      y. Paraffin sealing.
      z. Water encroachment.
    b. Engineering and economic:
      w. Methods of operation.
      x. Wastage.
      y. Cost of development, equipment, and operation.
      z. Price of oil.

The term "depreciation" is sometimes used to include functional depreciation, but usually it is restricted to those factors here listed under ordinary wear and tear. Rarely, if ever, has it been made to include losses due to accidental causes.

Ordinary Wear and Tear.—Bolts may be loosened by vibration, thus permitting further jarring and damage from the same source. Moving parts are subject to impairment through friction or abrasion; they may also become overheated. Damage resulting from these causes may be prevented by adequate systems of lubrication, effective cooling devices, and efficient inspection. Threads on tubing may become worn, and if this wear is excessive, the tubing may drop back into the hole when it is being "pulled," thus causing an expensive fishing job.

Chemical activity causes the rusting of materials exposed to the elements, the corrosion of casing by the action of salt water, and the deterioration by electrolysis of buried horizontal pipes. Rust requires the presence of water and oxygen. It is more effective in moist than in arid climates. The rapidity of corrosion is dependent largely upon the chemical content of oil waters. In the Coalinga field of California, steel and iron casing are destroyed in some wells in from 2 to 5 years. Similar high rates exist in many of the Gulf Coast fields, but elsewhere the rate is ordinarily much slower. The effectiveness of electrolysis from stray electric currents is restricted to the neighborhood of electrical power transmission lines, telephone and telegraph lines, and electric car lines, and even here its importance is questioned.

Microscopic organisms do considerable damage to wooden structures, causing them to decay and rot.

Functional Depreciation.—Equipment may be abandoned, with consequent shortening of useful life, either through inadequacy to meet additional requirements or through obsolescence. When central powers are employed on a lease they may be inadequate to meet new demands placed upon them when wells are deepened or new ones drilled.

Losses in value from the above causes are grouped together under functional depreciation, which may be defined as that depreciation due not to physical impairment, but rather to those conditions external to the physical equipment, and which have a bearing upon its adaptability for use.

Depletion.—Depletion in its broadest sense includes any loss in value due to decrease in the amount of recoverable

reserves; it is not concerned with those oil reserves which cannot be recovered. Its computation necessitates the assumption of a fixed set of conditions. Extraction of oil, paraffin sealing, water encroachment, wastage and loss of gas pressure reduce the recoverable reserves; while improved methods of operation, higher price of petroleum, and lower cost of development, equipment, and operation increase the recoverable reserves.

ALLOWANCE FOR LOSS IN VALUE

Valuation.—In the analytical appraisal of oil properties, the use of production-decline curves, the calculation of the economic limit, and the estimation of salvage value, all assume loss of value, either through the progressive exhaustion of the oil reserves or through depreciation. When profit and loss statements and balance sheets are used in the appraisal of the assets of an oil company, an adequate allowance for depletion and depreciation is necessary.

Maintenance.—The cost of keeping capital intact, that is, maintenance of both physical equipment and oil reserves, includes repairs, replacements, depreciation charges, and depletion allowances. The deterioration of the equipment necessitates repairs and replacements, for in spite of the most thorough efforts to preserve and repair the equipment it will wear out and depreciate in value. The rate of depreciation is dependent upon the care exercised in the maintenance of the property. Where structures have been neglected certain expenditures, usually grouped together under the term "deferred maintenance," will be required to restore the property to good condition. This expenditure may be much greater than the original cost of maintenance would have been, as a "stitch in time saves nine." Deferred maintenance always reflects negligence and discredits the management or financial ability of any concern.

CALCULATION OF DEPLETION AND DEPRECIATION

The actual loss in value represented by depletion and depreciation is independent of the method employed in their computation, date of acquisition of the property, interpretation of the Federal income tax laws, or methods of accounting. Nevertheless, cognizance must be taken of the foregoing factors when considering the allowance to be deducted for depletion and depreciation. Correct accounting permits the depletion of development costs

only when they have been charged to capital; the Federal income tax laws may permit the substitution of value for cost, depending in many cases upon the date the property was acquired. The value or cost of the physical equipment is the basis for determining depreciation; the value or cost of the oil reserves is the basis for determining depletion. The methods used in calculating depletion have a more rational basis than those used in computing depreciation, although some of these methods are employed for both purposes. The various methods give widely divergent results.

METHODS EMPLOYED IN CALCULATING DEPRECIATION AND DEPLETION

A. Used primarily for computing depreciation:
   1. Straight-line method.
   2. Fixed percentage method.
   3. Sinking fund method.
   4. Replacement method.
B. Used primarily for computing depletion:
   1. Valuation method.
   2. Reduction-in-flow method.
   3. Unit cost method.
   4. Maintenance-of-output method.

DEPRECIATION

Straight-line Method.—Due to its simplicity, the straight-line method is used in the calculation of depreciation more than all other methods combined. Equal annual amounts are deducted for depreciation throughout the life of the property. The total of these amounts when added to salvage value should equal the cost of the equipment, or value as of some basic date. The division into annual amounts may be accomplished in two distinct ways: (1) a constant value or cost may be used, in which all calculations are based upon the original cost or value; (2) a shrinking value may be used, in which depreciation is deducted annually and all calculations are based on the remaining value.

Assume that a tank cost $120 and is estimated to have a life of 10 years with a salvage value at the end of that time of $20. The problem is to distribute the depreciation allowance over the 10 years.

Total value	$120.00
Salvage value	20.00
Loss in value due to depreciation	$100.00
Estimated life	10 years

CONSTANT VALUE METHOD

Year	Rate of depreciation, per cent	Depreciable value (original value less salvage value)	Amount of depreciation	Remaining value at end of year
First	10	$100.00	$10.00	$110.00
Second	10	100.00	10.00	100.00
Third	10	100.00	10.00	90.00
Fourth	10	100.00	10.00	80.00
Fifth	10	100.00	10.00	70.00
Sixth	10	100.00	10.00	60.00
Seventh	10	100.00	10.00	50.00
Eighth	10	100.00	10.00	40.00
Ninth	10	100.00	10.00	30.00
Tenth	10	100.00	10.00	20.00

The shrinking value method arrives at the same result through a slightly different method of computation. The value of the equipment is determined at the beginning of each year and the depreciation rate computed in accordance with the remaining life of the property.

SHRINKING VALUE METHOD

a	b	c	d	e	f	g	h
Year	Years remaining	Rate of depreciation, per cent. $\left(c = \frac{100}{b}\right)$	Remaining value at beginning of year (same as h for preceding year)	Salvage value	Depreciable value (f = d − e)	Amount of depreciation (g = c × f)	Remaining value at end of year (h = d − g)
First	10	10	$120.00	$20.00	$100.00	$10.00	$110.00
Second	9	11⅑	110.00	20.00	90.00	10.00	100.00
Third	8	12½	100.00	20.00	80.00	10.00	90.00
Fourth	7	14⅜	90.00	20.00	70.00	10.00	80.00
Fifth	6	16⅔	80.00	20.00	60.00	10.00	70.00
Sixth	5	20	70.00	20.00	50.00	10.00	60.00
Seventh	4	25	60.00	20.00	40.00	10.00	50.00
Eighth	3	33⅓	50.00	20.00	30.00	10.00	40.00
Ninth	2	50	40.00	20.00	20.00	10.00	30.00
Tenth	1	100	30.00	20.00	10.00	10.00	20.00

The use of a constant value is quite generally employed when computing depreciation; the shrinking value method is more commonly employed in the computation of depletion.

Fixed Percentage of Remaining Value.—In the fixed percentage method, a shrinking value is used. From the original cost or value, annual deductions for depreciation are successively subtracted, and depreciation is computed as a fixed percentage of this remaining value. For example, a tank cost $1,066.67 and a 25 per cent rate of depreciation is to be used. The depreciation for the first year is 25 per cent of $1,066.67, or $266.67, leaving a remaining value of $800; the depreciation for the second year is 25 per cent of $800, or $200; for the third year, 25 per cent of $600, or $150, and for the fourth year, 25 per cent of $450, or $112.50, leaving an unextinguished value at the end of 4 years of $337.50. The amount that is charged to depreciation becomes less each successive year, and the original cost cannot be entirely extinguished.

The mathematics of this method are somewhat complicated. A common problem is to determine the rate of depreciation required to reduce the cost of equipment to an estimated salvage value in a given number of years. For this purpose the following formula may be used:

$$r = 1 - \sqrt[n]{\frac{s}{c}}$$

Where r = the annual rate of depreciation to be applied against the remaining cost.

n = the life of the asset in years.
s = salvage value.
c = original cost.

Example.—Assume that a string of casing cost $2,441.40, and has a life of 6 years, with an estimated salvage value of $640. Determine the annual rate of depreciation.

$$r = 1 - \sqrt[n]{\frac{s}{c}} = 1 - \sqrt[6]{\frac{640.00}{2,441.40}} = 1 - \tfrac{4}{5} = \tfrac{1}{5}$$

If the casing cost $2,441.40, an annual rate of depreciation of 1 in 5 is required to reduce this cost in 6 years to a salvage value of $640, as is seen from the following analysis.

FIXED PERCENTAGE METHOD

Year	Amount returnable through depreciation	Depreciation (at 20 per cent annually)	Remaining value
First	$2,441.40	$488.28	$1,953.12
Second	1,953.12	390.62	1,562.50
Third	1,562.50	312.50	1,250.00
Fourth	1,250.00	250.00	1,000.00
Fifth	1,000.00	200.00	800.00
Sixth	800.00	160.00	640.00

The chief advantage of the fixed percentage method is the deduction of the greatest depreciation during the early years of a property, when the income ordinarily is largest; but the same advantage may be obtained more scientifically by the use of the unit cost method described in connection with depletion.

Sinking Fund Method.—The distinctive feature of the sinking fund method is the provision of a fund to amortize the investment. At the time the equipment is abandoned the amounts placed in the fund, together with interest earned and income from salvage, should equal the original cost. The annual increments to the fund may be determined by any convenient formula, including those discussed, provided allowance is made for the interest earned, which materially reduces the annual deductions for depreciation.

In some instances the sinking fund and income from salvage are expected to return interest as well as the initial investment. The problem then becomes more complicated, necessitating computations for interest on the original investment and on the annual instalments to the sinking fund. The interest postulated in connection with the investment usually exceeds that earned by the sinking fund. These two computations for interest result in increasing the annual deduction for depreciation.

Replacement Method.—The maintenance of a business is dependent upon the replacement of worn-out structures. Allowances sufficient to amortize the original cost may or may not be adequate to meet the cost of replacement, and it is upon replacement costs rather than upon the original costs that the computations of this method are based. These computations may be

based on either the straight-line or fixed percentage methods, with or without the use of a sinking fund, although the employment of a sinking fund is more in harmony with the spirit of the replacement method.

As the costs of structures vary from time to time difficulties are encountered in the application of the replacement method. Either a changing base to agree with current prices must be used, necessitating numerous corrections, or predictions must be made of replacement costs as of date of abandonment. Such predictions are subject to great error. The replacement method implies a departure from the true meaning of depreciation, which is a loss that has occurred, and its computation should be considered in the light of past history rather than future needs.

Income Tax Requirements.—The Federal income tax regulations prescribe that depreciation should be based on the original cost of equipment, less salvage value, though in certain instances value as of some basic date may be substituted for cost. No recognition is taken of allowances for interest as in the sinking fund method, or for subsequent price changes as in the replacement method. The rates of depreciation suggested by the Treasury Department for income tax purposes are given in the Appendix.

Depletion

Valuation Method.—Since depletion and depreciation are losses in value, it might appear logical to value a property or structure on two separate dates and use the difference in value as a measure of the loss sustained, but the method is neither as simple nor as sound as it would first appear.

During periods of increasing prices there may be little or no loss in market value, second-hand equipment in many instances selling above original cost. During periods of declining prices the loss in value will be correspondingly great. If the valuation method is used, little or no depreciation and depletion would be recorded in periods of activity and increasing prices, but during periods of depression excessive depletion and depreciation would be recorded.

Owing to changes in value, certain compromises have been effected in the application of this method. A constant value per barrel of daily production is used, but with variations in the price of oil this arbitrary procedure results in valuations

which do not agree with true values. During periods of development, values are frequently greater at the end of the year than at the beginning, owing to increased production. It is customary to offset this increase in value by the cost of development, although there is seldom any agreement between the two, and neither of them can logically be included in the computation of depletion. In the application of the valuation method, depletion is determined by adding development cost to the value of a property at the beginning of the year and subtracting from this total its value at the end of the year. For example, if the value of a property January 1, 1923, and January 1, 1924, were $100,000 and $80,000 respectively, and if $50,000 were expended for development in 1923, the depletion would be $100,000 + $50,000 − $80,000 = $70,000. But if the increase in value exceeds the cost of development, the valuation method is inapplicable, as it fails to record any depletion, although immense quantities of oil may have been extracted.

Reduction-in-flow Method.—In the reduction-in-flow method the decline in daily production is used as a measure of depletion. The method closely parallels that of the valuation method, but values are not established at the end of each year and development costs are treated differently. A property has a value of $100,000 January 1, 1923, and a daily production of 100 barrels. By January 1, 1924, it is producing only 80 barrels a day; the decline in production for 1923 is 20 barrels, or 20 per cent, which when applied against $100,000, the value on January 1, 1923, gives $20,000 as the depletion. The limitations of the reduction-in-flow method are analogous to those of the valuation method. Where production increases, due to drilling activity, changes in method of operation, or any other cause, no depletion is recorded. Prior to 1918, the Federal income tax laws permitted the use of this method if the production was settled and if the reserves could not be readily ascertained.

Unit Cost Method.—Two computations are involved in the unit cost method; first, the unit cost is determined by dividing the cost or value of the oil reserves by the number of barrels of recoverable oil; second, depletion is determined for a given period by multiplying the production for this period by the unit cost. This is the most scientific method yet devised, and there are no inconsistencies, provided estimates of values and reserves are correct. The chief objection to its use is the amount

of work involved, necessitating as it does, an estimation of recoverable reserves. The Federal Government has authorized this method for the computation of depletion for taxation purposes.

An example will illustrate the calculations involved. The estimated oil reserves are 200,000 barrels, the value of these reserves is $100,000, and the production for the last 3 years is 120,000, 40,000, and 20,000 barrels respectively. The depletion unit is obtained by dividing value by reserves, $100,000 ÷ 200,000 = 50 cents. Annual depletion is obtained by multiplying the annual production by the depletion unit, 120,000 × 50 cents = $60,000; 40,000 × 50 cents = $20,000; 20,000 × 50 cents = $10,000; the depletion for these 3 years is thus found to be $60,000, $20,000, and $10,000 respectively.

In the accompanying depletion schedule (Table VIII) the following facts are assumed:

Value of oil reserves as of January 1, 1919	$1,000,000
Estimated reserves as of January 1, 1919	2,500,000 barrels
Value added by discovery of oil in deeper sand, May 5, 1922	$ 900,000
Reserves added by the above discovery	1,500,000 barrels
Production by years:	
1919	1,200,000 barrels
1920	500,000 barrels
1921	300,000 barrels
1922	700,000 barrels
1923	400,000 barrels
1924	250,000 barrels

Maintenance-of-output Method.—The object of the maintenance-of-output method, as its name implies, is to provide adequate funds for the drilling of sufficient wells to maintain a constant output; it bears the analogous relation to depletion that the replacement method does to depreciation.

Three factors determine the cost of maintaining production; first, the rate of decline in yield of the wells; second, the cost of drilling and equipping new wells in terms of their production; third, the decrease in initial production of new wells as the property is drilled and gas pressure taken off the sands, etc.

In studying this method the requisites of a field which can be used as a type are as follows:

1. Production should be constant throughout the period.

2. No wells should be shut down—or else allowance must be made for them.

TABLE VIII.—DEPLETION SCHEDULE

	1919	1920	1921	1922	1923	1924	1925
A–Capital sum at beginning of year	$1,000,000	$520,000	$320,000	$ 200,000	$715,000	$495,000	$357,500
B–Amount added during the year.	.....	.....	.....	$ 900,000			
C–Capital sum subject to depletion (A + B).....	$1,000,000	$520,000	$320,000	$1,100,000	$715,000	$495,000	$357,500
D–Estimated recoverable reserves at beginning of year, barrels....	2,500,000	1,300,000	800,000	500,000	1,300,000	900,000	650,000
E–Reserves added during the year, barrels.....	.....	.....	.....	1,500,000			
F–Total reserves (D + E), barrels.	2,500,000	1,300,000	800,000	2,000,000	1,300,000	900,000	650,000
G–Unit cost (C ÷ F).....	$.40	$.40	$.40	$.55	$.55	$.55	$.55
H–Production per year, barrels...	1,200,000	500,000	300,000	700,000	400,000	250,000	
I–Depletion for year.....	$480,000	$200,000	$120,000	$385,000	$220,000	$137,500	

3. There should be no bringing in of an exceptionally large yield—or else allowance must be made for it.

4. There should be no opening up of virgin territory.

Cost of drilling will be constantly less, owing to improved methods and particularly to the increasing use of the rotary drill (speaking of the California fields).

The following figures are of the Coalinga Field from August, 1912, to August, 1913:

Greatest variation from average production	8 per cent
Average variation (on a monthly basis)	2.8 per cent
Total production	19,313,000 barrels
New wells completed	78
Total wells	843
Greatest variation from average number of suspended wells	8.6 per cent
Cost of these 78 wells (total)	$2,176,573
Cost per barrel (of year's production) for above wells	11.26 cents
Number of wells necessary to maintain production of total number of wells at beginning of year	9.23 per cent

The following figures apply to the Sunset-Midway field:

Cost per barrel (of year's production)	9.6 cents
Proportion of new wells necessary to maintain production	14.8 per cent

The following figures apply to all California fields:

Cost per barrel (of year's production)	10.4 cents
Proportion of new wells necessary to maintain production	8.22 per cent[1]

[1] LOMBARDI, M. E.: "Cost of Maintaining Production in California Oil Fields," *Trans.* Am. Inst. Min. Eng., vol. 52, pp. 218–223.

From the foregoing discussion it is seen that for every barrel of oil produced the following amounts are required to provide for the drilling of a sufficient number of wells to maintain production:

	CENTS
1. Average for all California fields	10.4
2. Sunset-Midway field	9.6
3. Coalinga field	11.26

The above amounts do not provide for the increased cost of operating small wells as compared with large wells, for the leasing of new lands, and for certain miscellaneous expenditures.

CHAPTER IX

METHODS OF VALUATION

Differences in the viewpoint of engineers, operators, and accountants have lead to the development of many methods for valuing oil lands, some being particularly adapted for speed and others for accuracy. Different methods are used for determining productive value and market value; new methods are continually being evolved to meet special conditions. The need for accuracy is greater in valuations for commercial than for taxation purposes. Where a group is considered, errors in one property may be offset by compensating errors in other properties. Accuracy in the analysis of a given factor affecting value is important only when somewhat the same degree of accuracy can be maintained in the determination of all other factors, but the accurate determination of all factors requires much time and often accuracy must be sacrificed for speed when time is limited.

There are five general methods of valuation:

1. The analytical method, in which an analysis is made of the factors determining future income, and the present worth of the property is determined accordingly.
2. Arbitrary methods, in which "rule-of-thumb" formulas are applied.
3. The sales valuation method, in which sales and transfers are analyzed and comparison made with a given property.
4. The accounting method, in which values of properties are determined from an analysis of profit and loss statements and balance sheets.
5. The comparative method, in which comparison is made between different properties or different types of properties, as in the determination of the value of a royalty interest from a predetermined value of the working interest.

Present Value Method

The present value method, sometimes called the "analytical appraisal" because of the analysis required of the various ele-

ments, and also known as the "engineering appraisal" because of its origin and use by engineers, is the most scientific of all the methods so far developed. Its use is confined to the determination of the productive value, or the present value, of the future expected net income. Two steps are involved: first, the correct estimation of the elements of value, as oil reserves, rate of extraction, price of oil, cost of obtaining the oil, and proper discount factor; second, the mathematical calculations involved, which can best be illustrated by a few examples.

First Procedure.—Assume that an operator has a lease on 40 acres, on which two producing wells have been drilled and two wells are about to be drilled, and when these wells are completed the tract will be considered fully developed, the spacing for the field being 10 acres to a well. The cost of drilling and equipping the two wells was $40,000, or an average per well of $20,000. Similar expenditures will probably be incurred by the other two wells; operating costs will probably average $2,500 per well a year; the royalty rate is one-eighth. The present selling price of oil is $1.90, which is assumed to remain constant. Discount is computed at an interest rate of 10% compounded semi-annually; the income for a given year is assumed to be received in the middle of the year. The estimated income from salvage when the property is abandoned is $3,000. From an analysis of the geological conditions and production from surrounding wells, it is estimated that each of the four wells will average 20,000 barrels the first year. The decline in production will be in accordance with the figures given below:

Year	Barrels
First	20,000
Second	13,200
Third	8,700
Fourth	6,000
Fifth	4,200
Sixth	3,000
Seventh	2,200
Eighth	1,650
Ninth	1,250
Tenth	1,000

Economic Limit.—The first determination is the economic limit. If the operator is to meet expenses the annual income must equal the annual operating expense, which is $2,500; with oil selling at

$1.90 a barrel, the operator must receive 2,500 ÷ 1.90 = 1,316 barrels; as the operator of the oil property receives only seven-eighths of the oil produced, the total production must be $\frac{8}{7} \times 1{,}316 = 1{,}504$ barrels. The economic limit is thus determined to be 1,504 barrels, which necessitates discarding the production for the ninth and tenth years. The value may now be computed in the manner shown in Table IX.

Calculations Involved.—The year and the corresponding gross production are listed in Columns A and B; the price of oil, annual operating expense, and appropriate discount factors are listed in Columns D, F and H respectively. From these basic figures the results indicated in the other columns are obtained. The net production credited to the operator is obtained by subtracting from gross production the royalty oil. The production listed in Column C is seven-eighths of that shown in Column B. The price of oil and the net production are multiplied together to obtain the gross income, as shown in Column E. In Column G, net income is obtained by subtracting operating cost from gross income. The application of discount factors to income determines the present value of the production for each year, which is shown in Column I; the sum of these values is the present value of the expected production throughout the life of the property, and is found to be $65,845.08. The estimated salvage value is $3,000, but as this amount is not received until the end of the eighth year, its present worth when discounted is only $1,374. The total value of both oil production and income from salvage is $67,219.08, from which drilling and equipping cost of $20,000 must be subtracted to determine the value of one location, which is $47,219.08. The total value of the two producing wells and the two undrilled locations on the property is $228, 976.32.

Other Assumptions.—In the foregoing example, the price of oil and yearly cost of operation per well are assumed to remain constant; the results of any other assumptions can readily be substituted in Columns D and F. It is commonly assumed that the cost of producing each barrel of oil is the same throughout the life of the property. If the operating cost is 40 cents per barrel and the price of oil $1.90, the net income is $1.50 per barrel, which would be listed in Column D and the heading changed accordingly; gross income and operating cost, Columns E and F, would then be omitted.

TABLE IX

A Year	B Gross production, barrels	C Net production, barrels	D Price of oil	E Gross income (E = C × D)	F Operating expense	G Net income (G = E − F)	H Discount factor	I Present value (I = G × H)
First	20,000	17,500	$1.90	$33,250.00	$2,500.00	$30,750.00	.952	$29,274.00
Second	13,200	11,550	1.90	21,945.00	2,500.00	19,445.00	.864	16,800.48
Third	8,700	7,612	1.90	14,462.80	2,500.00	11,962.80	.784	9,378.84
Fourth	6,000	5,250	1.90	9,975.00	2,500.00	7,475.00	.711	5,314.72
Fifth	4,200	3,675	1 90	6,982.50	2,500.00	4,482.50	.645	2,891.21
Sixth	3,000	2,625	1.90	4,987.50	2,500.00	2,487.50	.585	1,455.19
Seventh	2,200	1,925	1.90	3,657.50	2,500.00	1,157.50	.530	613.47
Eighth	1,650	1,444	1.90	2,743.60	2,500.00	243.60	.481	117.17

Present value of expected production		$65,845.08	
Salvage value:			
Estimated value at date of abandonment	$3,000.00		
Discount factor	.458		
Present worth	1,374.00	1,374.00	
Total value of one well		$67,219.08	
Value of two wells			$134,438.16
Cost of drilling and equipping		20,000.00	
Value of one location		$47,219.08	
Value of two locations			94,438.16
Total value of property			$228,876.32

Second Procedure.—The calculations shown in Table IX may be greatly reduced if speed is required or many valuations are

TABLE X

A Year	B Net production, barrels	C Discount factor	D Production discounted
First	17,500	.952	16,600.00
Second	11,550	.864	9,979.20
Third	7,612	.784	5,967.81
Fourth	5,250	.711	3,732.75
Fifth	3,675	.645	2,370.37
Sixth	2,625	.585	1,535.62
Seventh	1,925	.530	1,020.25
Eighth	1,444	.481	694.56
Total		5.552	41,960.56
Price of oil			$ 1.90
Present value of gross operating income			$79,725.06
Cost of operations:			
Annual operating expense	$ 2,500.00		
Factor	5.552		
Capitalized cost	13,880.00		13,880.00
Present value of expected production			65,845.06
Salvage value:			
Estimated value at date of abandonment	$ 3,000.00		
Discount factor	.458		
Present worth	1,374.00		1,374.00
Total value of one well			$67,219.06
Value of two wells			$134,438.12
Cost of drilling and equipping			20,000.00
Value of one location			$47,219.06
Value of two locations			94,438.12
Total value of property			$228,876.24

to be computed; necessarily the analysis is less clear and complete. To illustrate this procedure Table X is submitted, using the same assumptions as in the preceding table. The operations have here been reduced 30 per cent and if more years had been in-

volved the reduction in work would have been even greater. The chief difference between these two procedures is in the application of the discount factor; in Table IX discount is applied against net income, in Table X it is applied against both production and operating cost. After production has been discounted (using the second procedure), the discounted numbers are added and the sum multiplied by the price of oil to determine the present value of the gross income. Annual operating cost is multiplied by the sum of the yearly discount factors to determine the capitalized cost of operations. This capitalized cost is then subtracted from the present value of the gross income to determine the value of the production. The remainder of the calculations are the same as in the first procedure.

Graphic Representation.—A uniform price of oil and similar development, equipment, and operating expense may be used if valuations of a large number of individual wells in a given pool are required. The individual wells will, in general, follow the same decline curve, although different curves may be used for the different parts of the pool or for wells of different ages, and it may also be necessary to make allowances for the peculiarities of individual wells. Great differences exist in the total production of individual wells and their value; they are largely dependent upon variations in initial production. The relation between total value and initial production is more definite when the production considered is that of the first month rather than the first 24 hours. A valuation chart based upon the foregoing principles may be prepared and used in future appraisals. In the preparation of this chart, valuations are made of wells of various sizes and each well is plotted on the chart as a point. Using its value and initial production as the two coordinates, a line is then drawn through these points. If the initial production of a new well is known, its value may be estimated from the chart.

Direct Comparison of Income and Expenditures.—Frequently, the assumptions concerning production, price of oil, and costs are considerably in error. The results obtained by the present value method cannot be more accurate than the assumptions upon which they are based, and, consequently, the mathematical precision indicated is likely to be quite misleading. This precision is largely the result of applying accurate discount factors and may be eliminated by disregarding discount and directly comparing total income with total costs.

Assume that a property will produce 1,000,000 barrels of oil, which will sell at an average price of $2 a barrel, that operating expense will be 60 cents a barrel, and cost of development and equipment $200,000; no allowance is to be made for salvage value. The total operating costs, $600,000, plus development and equipment costs, $200,000, give a total expenditure of $800,000; the total income will be $2,000,000. On the basis of the foregoing analysis it is apparent that no one would be willing to pay $1,200,000 for the property, as there would be no profit. Assume that the prospective purchaser decides that his profit should be at least $300,000; to yield this profit, the purchase price cannot exceed $900,000. The profit necessary to make an investment attractive varies with the amount of risk involved and the length of time required for the return of the original investment.

Time Required to "Pay Out."—It is a common practice in the oil industry to consider that a property is not on a paying basis until the gross income has equaled all past expenditures, or, as it is usually expressed, until the property has "paid out." The length of time in which a property should pay out varies from 1 year, or even less where the decline is rapid, to 4 or 5 years in the case of slowly declining properties. Estimates may be made of this length of time, using as a basis the probable income and probable expenditures.

In some instances, valuations may advisedly be made by the direct comparison of total income and total expense, or on the basis of the time required to pay out. In general, these methods do not make sufficient distinction between properties with slowly declining production, where considerable allowance must be made for interest because of the slow return of the money invested, and those with rapidly declining production, where the interest allowance may be slight. A clear distinction between the value of these types of properties can only be obtained by the use of discount factors.

Arbitrary Methods

Pennsylvania Method.—Long before the development of scientific methods of appraisal, oil operators in Pennsylvania, the home of the American oil industry, were valuing oil lands by certain arbitrary rules developed through long years of experience. The Pennsylvania method values each barrel of daily production at 1,000 times the selling price of oil; this rule applies

only to fully developed properties, where the production is settled. If oil sells for $4 a barrel, the value per barrel of daily production is $4,000; and if a fully developed property has a settled production of 15 barrels, the value of the property is 15 × $4,000, or $60,000. Higher prices than indicated by the 1,000-to-1 rule are paid for royalty interests, or for fee property, or where there is an opportunity to increase production, either by improved methods of operation or by the development of proven but undrilled acreage. Lower prices must be accepted where the operating costs are excessive, or where the production is flush. The method can best be applied to a large number of properties where the resulting errors may be compensating; accuracy is greatly increased by the elimination of all properties to which the method obviously does not apply.

Modified Method.—The Pennsylvania method, though simple in application, has been rather severely and justly criticized, as it recognizes neither the ratio between operating expense and price of oil nor the rate of decline and hence total production. Much of the simplicity of the method may be retained even when allowance is made for these two factors. This modification of the Pennsylvania method is shown in Table XI. This table is based on more than 50 appraisals which differ from each other in the rate of decline of production, or in the ratio between operating expense and price of oil, or both; but in all of them the price used remained constant throughout the life of the well, a uniform rate of decline was assumed, and income was discounted as if received in the middle of the year. The discount factors were based on a rate of 10 per cent, compounded semi-annually.

The rate of decline as here used is the ratio between (1) the difference in production of two successive years, and (2) the production for the first one of these years. Thus, if a property produced 50,000, 30,000, and 18,000 barrels of oil in successive years, the decline would be 40 per cent. The assumption of a uniform rate of decline in production is inaccurate and results in undervaluations, varying from 5 per cent, or less, to 25 per cent and even more in exceptional cases. The annual rates of decline used were 50, 40, 30, 20, 10, 5, and 0 per cent; in the latter case income is considered as an annuity.

Operating expense is expressed in cost per barrel produced, and two assumptions were made: first, that of a constant operating cost per barrel throughout the life of the property, the economic

limit being considered as one-fifth of the first year's production; second, that of an increasing operating cost per barrel, the barrel cost being assumed to increase in the same ratio that production declines, thus maintaining a constant operating cost for the entire property; in this case, the economic limit is automatically determined as that point at which operating expense equals the price of oil.

Example I

Problem.—Determine the present value of a property whose yearly production for the last 3 years was 4,700, 4,220, and 3,800 barrels respectively, with a present daily production of 10 barrels. The selling price of oil is $3.50, and is assumed to remain constant. The operating expense is determined to average $1.40 per barrel throughout the life of the property.

Solution.—(1) The rate of decline is approximately 10 per cent.

$$\frac{4{,}700 - 4{,}220}{4{,}700} = \frac{480}{4{,}700} = 10 \text{ per cent } +$$

$$\frac{4{,}220 - 3{,}800}{4{,}220} = \frac{420}{4{,}220} = 10 \text{ per cent } -$$

(2) The ratio of operating expense to price of oil is $\frac{1.40}{3.50} = 40$ per cent. This ratio is constant throughout the life of the property and hence the upper portion of Table XI is to be used.

Column III (Table XI) refers to properties where the annual rate of decline is 10 per cent; line 3 to properties where the ratio of operating expense to price of oil is 40 per cent; the factor found in Column III, line 3, is 1,020.

The price of oil is $3.50, using the factor 1,020; the value per barrel of daily production is $3.50 × 1,020 = $3,570. As the daily production is 10 barrels, the total value of the property is $35,700.

Example II

The same conditions postulated in Example I will be used in Example II, but with this difference, operating cost per barrel at date of valuation is $1.40, and that this cost is assumed to increase in the same ratio that production declines. This assumption necessitates the use of the lower portion of Table XI; from the table the factor is found to be 620. Oil sells at $3.50 per barrel. The value per barrel of daily production is 620 × $3.50

TABLE XI

Multiply the price of oil by the following factors to obtain the value per barrel of daily production for a given property

	Line	Operating cost \ Annual rate of decline, per cent	Column I 0	Column II 5	Column III 10	Column IV 20	Column V 30	Column VI 40	Column VII 50
Ratio of average operating cost over entire life of property to price of oil at date of valuation.	1	Royalty, no cost	3,800	2,400	1,700	1,000	700	500	375
	2	20% of income	3,040	1,920	1,360	800	560	400	300
	3	40% of income	2,280	1,440	1,020	600	420	300	225
	4	60% of income	1,520	960	680	400	280	200	150
	5	80% of income	760	480	340	200	140	100	75
Ratio of operating cost to price of oil at date of valuation.	6	Royalty, no cost	3,800	2,400	1,700	1,000	700	500	375
	7	20% of income	3,040	1,700	1,100	640	400	300	200
	8	40% of income	2,280	1,000	620	320	210	120	.....
	9	60% of income	1,520	490	230	120	.....	.....	.....
	10	80% of income	760	130	.....	.....	.....	.....	.....

The above factors have been given in convenient round numbers and no attempt has been made to make them correct beyond one or two significant figures.

= $2,170, and as the daily production is 10 barrels, the total value of the property is $21,700.

The use of this table permits the rapid calculation of approximate values and may serve as a useful check on more detailed and exact methods, but widespread application is not advisable. The results obtained are undervaluations and should not be accepted where accuracy is required.

Analysis of Sales

The market value of oil lands may be greater or less than their productive value; a knowledge of both is essential. If the market value is in excess of the productive value, it is to the operator's advantage to sell; if less than the productive value, it is advisable to buy.

Oil lands are usually leased by the companies which operate them, although they are sometimes purchased outright. The terms of transfer differ greatly as to cash and contingent payments and obligations assumed. Many leases have been secured without the payment of a bonus, while in more than one instance, over $1,000,000 have been paid as a bonus for a lease on a 160-acre tract. Many factors cause these variations. Geological structure, proximity to production, size of the producing wells, rapidity of their decline, costs of development, equipment, and operation, and price of oil, and certain psychological and financial factors, as undue excitement or forced sales, must all be considered. The proper classification and analysis of sales and other transactions are dependent upon an adequate knowledge of the foregoing factors and are essential to a clear conception of market value.

Undeveloped Lands.—Oil lands may be classified as fully developed, partially developed, and entirely undeveloped—each group should be studied separately. The first and the last are easier to analyze than the second, which combines many of the difficulties of the other two.

When studying the sales price of undeveloped lands, attention should be restricted to tracts lying within a given geological province and where geological conditions are fairly uniform. Under these conditions, standard prices may exist for distinct types of acreage, although a number of factors affecting sales and leases cause variations from these standards. Frequently, a general price may be established for acreage "offsetting production"

or adjoining a drilling well. In many transactions the cash payments are of secondary importance; excessive royalties, bonus payments out of oil produced, and a stipulated drilling program may be the chief items of the contract. In some districts 3,000 to 5,000 acres of wildcat land, if located favorably structurally, are commonly given in exchange for a drilling contract, but in proven territory only a half interest on a 20- or 40-acre tract may be given. The costs and obligations assumed or the production required to offset expenditures may be used as a basis of determining the value placed upon the property by the contracting parties.

Developed Acreage.—Production is usually classified as either flush or settled, although there is no definite separation between the two. The age of the well largely affects the rate of decline in production. Differences in this rate are much greater for wells of flush production, and, consequently, standard prices are more difficult to establish than for wells with settled production. The unit in which values of settled production are expressed is the barrel of daily production already discussed in connection with the Pennsylvania method of valuation.

In a given field, a current price for settled production is often well established, as $1,000 per barrel of daily production. In many cases, this price can only be established after an analysis of a number of sales; the sales price should be divided by the number of barrels of daily production to determine the value per barrel of daily production. Assume that a value of $1,000 is established when oil is selling at $2 a barrel; the ratio between the two is 500 to 1, this ratio can be used in the same manner as the 1,000-to-1 ratio described in the Pennsylvania method. Thus, when oil is selling at $1.75, the value per barrel of daily production is $500 \times \$1.75 = \$875$. Caution must be exercised in the application of the foregoing principle, as the profit per barrel decreases in a much greater ratio than the price of oil, unless operating costs are at the same time reduced proportionately.

Accounting Method

Balance sheets and financial statements usually reveal the investment in oil lands rather than their true value, but when a company issues stock to acquire assets it is necessary that these assets be valued. They are usually so valued as to conform with the face value of the stock issued for them, and the valuations

do not ordinarily reflect the true market value or the productive value. The productive value of a property is dependent upon its future expected profits; under certain conditions this value is reflected in the profit and loss statement, provided adequate allowance has been made for depletion and depreciation. The use of the profit and loss statement in connection with valuations may best be applied to developed properties, and even here mismanagement, unexpected changes in the price of oil, or operating expense may cause discrepancies between the original value and that indicated by the profit and loss statements.

During the years 1915, 1916, and 1917 the A B C Oil Company operated, as a partnership, certain fully developed oil lands. On December 31, 1917, this partnership was dissolved and the A B C Petroleum Corporation was organized and acquired the assets of the partnership, for which stock was issued. The financial tsatus of the A B C Petroleum Corporation as of January 1, 1918, as reflected by their statement of that date, is given below:

THE A B C PETROLEUM CORPORATION

BALANCE SHEET JANUARY 1, 1918

Assets		
Current Assets:		
Cash	$ 18,044.19	
Accounts Receivable	32,960.71	
Oil in Storage	5,090.10	
Total Current Assets		$ 56,095.00
Fixed Assets:		
Leaseholds	$1,000,000.00	
Physical Equipment	250,000.00	
Total Fixed Assets		1,250,000.00
Total		$1,306,095.00
Liabilities		
Current Liabilities:		
Accounts Payable	$ 11,095.00	
Notes Payable	30,000.00	
Total Current Liabilities		41,095.00
Capital Stock		1,265,000.00
Total		$1,306,095.00

In 1918 the price of oil remained constant, the management was good, and no expenditures were made for drilling as the property was entirely developed. Consequently, the profit and loss statement should reflect the earning ability of the property. The estimated oil reserves were 250,000 barrels as of January 1, 1918, and 62,109 barrels of oil were extracted during the year. Using the unit cost method, depletion is computed as $248,436 and depreciation as $62,109. A profit and loss statement for the year 1918, and a balance sheet as of December 31, 1918, are here submitted.

THE A B C PETROLEUM CORPORATION

STATEMENT OF INCOME AND PROFIT AND LOSS, FOR THE YEAR ENDED DECEMBER 31, 1918

Earnings:		
Sales		$146,139 95
Inventory as of January 1, 1918	$ 5,090.10	
Inventory as of December 31, 1918	14,059.35	
Gain in Inventory		8,969.25
Gross Profit		$155,109.20
Expense:		
Operating Expense	$ 51,090.19	
Administrative Expense	19,024.71	
Taxes	790.05	
Total		70,904.95
Net Profit from Operations		$ 84,204.25
Reserves:		
Depreciation	$ 62,109.00	
Depletion	248,436.00	
Total		$310,545.00
Net Loss		*$226,340.75*

THE A B C PETROLEUM CORPORATION
BALANCE SHEET DECEMBER 31, 1918

Assets

Current Assets:		
Cash	$ 34,450.00	
Accounts Receivable	55,996.50	
Oil in Storage	14,059.35	
Total Current Assets		$ 104,505.85

Fixed Assets:		
Leaseholds	$1,000,000.00	
Physical Equipment	250,000.00	
Total Fixed Assets		1,250,000.00
Total		$1,354,505.85
Liabilities		
Current Liabilities:		
Accounts Payable	$ 5,301.60	
Total Current Liabilities		$ 5,301.60
Reserves:		
Reserves for Depreciation	$ 62,109.00	
Reserves for Depletion	248,436.00	
Total Reserves		310,545.00
Capital Stock		1,265,000.00
Deficit		*226,340.75*
Total		$1,354,505.85

The productive value of a property has been defined as that amount which the future income will repay after making due allowance for interest and risk. The productive value of the properties of the A B C Corporation for the year 1918, as indicated by the profit and loss statement, does not agree with the value indicated by the balance sheet as of January 1, 1918. If the value of the oil property had been correctly estimated at date of incorporation, the total earnings would be sufficient to provide for all expenditures and repay the amounts represented by the estimated values, together with a fair allowance for profit. On the basis of correct valuations, all expenditures, together with a reasonable deduction for depletion and depreciation and a fair allowance for profit on the average investment in the oil property for the year, would be realized from the earnings for a given year. But in the example cited, such is not the case. The earnings, after deducting expenditures, are only sufficient to amortize the value placed upon the physical equipment and render a fair return upon this value. The profit and loss statement shows a gross profit of $84,204.25; after deducting the reserves for depreciation this profit is reduced to $22,095.25, and when the reserves for both depreciation and depletion are deducted, a loss of

$226,340.75 is indicated. The physical equipment is valued at $250,000 January 1, 1918, and after deducting depreciation of $62,109 for the year, the remaining value is $187,891; the average value for the year is approximately $219,000. Based on this average value, the net profit from operations after deducting depreciation is a little more than 10 per cent. But no allowance had been made for the depletion charge of $248,436. If the total earnings are required to amortize the physical equipment and render a fair return for interest and risk based upon the average value ($219,000) of the physical equipment for the year, then there is no value for leaseholds, and the assets shown on the balance sheet as of January 1, 1918, are overvalued to the extent of $1,000,000. The elimination of the leasehold account from the balance sheet will also eliminate the item of depletion from the profit and loss statement; these financial reports will then be in harmony. The use of profit and loss statements and balance sheets emphasizes the accounting feature of valuation, but they cannot be used unless proper adjustments for depletion and depreciation have been made, which in turn, necessitate a correct estimation of the oil reserves.

Valuation of Royalties

The distinctive feature of valuing oil royalties is the elimination of all items of cost, which greatly simplifies their valuation, although many men conversant with the valuation of working interests find it difficult to value royalties. The following formula indicates the relation between the values of royalties and working interests:

$$R = \frac{r \times O \times P}{(1 - r)(P - C)}$$

Where R = value of royalty interest.
r = royalty rate.
O = value of operating interest.
P = price of oil per barrel.
C = all further costs per barrel.

This formula is of general application and may be used in connection with undeveloped as well as developed properties. All future costs, including development costs, costs for dry holes,

and operating costs, are represented by C in the formula. The use of this formula will probably be chiefly restricted to fully developed properties, and only the operating cost need then be given in C. The valuation of royalty interest from predetermined values of the working interest is the chief use of the comparative method.

CHAPTER X

VALUATIONS UNDER THE FEDERAL INCOME TAX LAWS

The Sixteenth Amendment.—Until the adoption of the sixteenth amendment in the spring of 1913, Federal laws levying taxes on income were declared to be unconstitutional, as taxes levied upon income were considered to be direct taxes and hence illegal, being contrary to that portion of the Constitution of the United States which declares "direct taxes shall be apportioned among the several States which may be included within this Union according to their respective numbers."[1] This provision of the Constitution was modified by the sixteenth amendment which reads: "The Congress shall have power to lay and collect taxes on incomes from whatever sources derived, without apportionment among the several States, and without regard to any census or enumerations."

Income Tax Laws.—Upon this brief amendment, several income tax laws and numerous regulations have been based. The discussion of these laws and regulations is here restricted to their relation to the valuation of oil properties, and the effect of these valuations upon depletion, depreciation, invested capital, and profit and loss arising from the sale of capital assets. The 1913 law placed an arbitrary limitation upon the amount of depletion and depreciation which could be deducted when computing the gross income from oil properties. These deductions, for the years 1913, 1914, and 1915, were limited to 5 per cent of the gross value of the product. This restriction was removed in 1916. Due to the entrance of the United States into the World War, tax rates were increased and new features were incorporated into the 1917 law. Allowance was first made for the hazardous nature of the oil industry in the 1918 law, when the discovery clauses were incorporated. Limitations were imposed upon deductions for depletion under the discovery clauses of the 1921 law, and certain book profits, which previously had been taxed, became exempt from taxation. In addition to the foregoing

[1] Article I, Sec. 2, Par. 3.

laws, various regulations have been issued from time to time and changes are being made more or less continually in the form of opinions, recommendations, and decisions emanating from various committees and individuals.

LEGAL STATUS OF VALUATIONS

In the computation of income, items of expense are deducted in the year in which they occur, while the cost of capital items is deducted through a series of depletion and depreciation deductions throughout the life of the property; the sum of these deductions, if based on the cost of the property should equal the original cost. In many instances, valuations as of some basic date form the basis for computing depletion and depreciation deductions. This value is also used when considering the profit arising from the sale of capital assets. The war and excess profits tax, effective on corporations prior to 1922, and on individuals in the year of 1917 only, is definitely related to invested capital; in the computation of invested capital, the cost of the assets is commonly used, but occasionally their value may be substituted. The substitution of value for cost varies with its application, whether in the determination of depletion, depreciation, invested capital, or profit from the sale of capital assets. Furthermore, the several tax laws differ greatly. With certain restrictions, valuations may be permitted on each of the following dates:

1. March 1, 1913.
2. January 1, 1914.
3. At date of organization of a corporation.
4. At date property was received as a gift or through inheritance.
5. At date of liquidation of a corporation.
6. Within 30 days of discovery.
7. At date of sale.

March 1, 1913

Depletion and Depreciation.—The first income tax law became effective March 1, 1913. After this date, profits from operations and sale of assets are taxable, but prior thereto neither income nor increase in values of assets were properly subject to taxation. Where properties have been acquired prior to March 1, 1913, their value as of this date may be used as a basis for computing depletion and depreciation deductions.

Sale of Capital Assets.—When determining the profit arising from the sale of capital assets, it is obvious that allowance must be made for the cost of the property, but if the property were acquired before March 1, 1913, and sold after that date, it is necessary to determine what portion of the profit should be attributed to the period prior to March 1, 1913, and what portion to the period subsequent thereto, as only the latter portion of the profit is taxable. The Federal Government has formulated the following rules to govern the losses which may be deducted, and the gains which are taxable from the sale of capital assets:

1. Sales price may be greater than the value as of March 1, 1913, which, in turn, may be greater than cost. The taxable gain is the difference between the value as of March 1, 1913, and sales price.

2. Sales price may be greater than cost, which, in turn, may be greater than the value as of March 1, 1913. The taxable gain is the difference between cost and sales price.

3. Sales price may be less than cost but greater than the value as of March 1, 1913. There is no taxable gain or deductible loss.

4. Sales price may be less than the value as of March 1, 1913, but greater than cost. There is no taxable gain or deductible loss.

5. Sales price may be less than cost, which, in turn, may be less than the value as of March 1, 1913. The deductible loss is the difference between cost and sales price.

6. Sales price may be less than the value as of March 1, 1913, which, in turn, may be less than cost. The deductible loss is the difference between the value as of March 1, 1913, and sales price.

These cases are illustrated by the following examples:

	Cost	Value as of March 1, 1913	Sales price	Taxable gain	Deductible loss
1.	$10,000	$15,000.00	$20,000.00	$ 5,000.00	
2.	10,000	5,000.00	20,000.00	10,000.00	
3.	10,000	3,000.00	5,000.00	None	None
4.	10,000	30,000.00	20,000.00	None	None
5.	10,000	15,000.00	5,000.00	.....	$5,000.00
6.	10,000	5,000.00	3,000.00	.....	2,000.00

Modifications for Depletion and Depreciation.—The foregoing rules are general and apply without any modification to stocks and bonds, agricultural lands, and assets not subject to depletion and depreciation. Assets subject to depletion and depreciation, as oil properties, necessitate certain adjustments in the application of these rules, as illustrated by the following examples. Operating profit is reduced by depletion and depreciation deductions, but these deductions likewise reduce the asset account and thus increase profits arising from the sale of capital assets. The unextinguished or remaining cost or value of wasting assets must be compared with the sales price when computing the profit or loss from their sale.

An oil property, purchased January 15, 1910, for $100,000 was sold May 1, 1918; its value March 1, 1913, was $120,000. Depletion and depreciation are subtracted to determine unextinguished cost or value.

Cost January 15, 1910		$100,000.00
Less:		
Depletion to date of sale, May 1, 1918	$30,000.00	
Depreciation to date of sale, May 1, 1918	22,000.00	52,000.00
Unextinguished cost		$ 48,000.00
Value March 1, 1913		$120,000.00
Less:		
Depletion to date of sale, May 1, 1918	$25,500.00	
Depreciation to date of sale, May 1, 1918	21,500.00	47,000.00
Unextinguished value		$ 73,000.00

If the sales price had been $75,000, there would have been a taxable gain of $2,000; if the sales price had been $60,000, there would have been neither taxable gain nor deductible loss; and if the sales price had been $40,000, there would have been a deductible loss of $8,000. If the unextinguished cost had been $73,000, and the unextinguished value $48,000, the deductible loss or taxable gain would have been the same as in these three cases.

Invested Capital.—The determination of invested capital is an accounting problem and involves the audit of a balance sheet. Assets should be entered at cost; this applies even where properties have been acquired prior to March 1, 1913. Depletion is not only deducted from income but also from the leasehold account, and thus enters into the determination of invested capital. If assets are entered at cost, obviously depletion should

be based on cost; but where properties have been acquired prior to March 1, 1913, depletion is usually based on the value as of this date. If this value is in excess of cost, the depletion deductions are excessive, and the asset account is reduced too rapidly. It then becomes necessary to add realized appreciation, which is the difference between depletion based on cost and depletion based on value as of March 1, 1913 (or other basic date). The net result of all these calculations is to reduce the asset account as if the depletion had been based on cost.

January 1, 1914

Valuations of assets as of January 1, 1914, may be used in the determination of invested capital both for individuals, under proper conditions, and for corporations where the assets have been acquired with stock. These valuations may be used only for the year 1917, and only in connection with the determination of invested capital.

At Date of Organization or Reorganization

The legal theory of the distinct and separate existence of a corporation is used in the interpretation of the 1917 and 1918 income tax laws. According to this theory, the stockholders of a corporation and the corporation itself are considered as distinct entities. If a group of 10 persons, each owning an equal interest in an oil property, organize an oil company to which they transfer this property, each of them receiving one-tenth of the stock, no change has occurred in beneficial interest and the transfer is one in form rather than ownership. Nevertheless, the property is considered as transferred from one legal entity to another, and the transaction is treated as a sale of the property by the individuals to the corporation, and is subject to taxation. The selling price to the individuals and the purchase price to the corporation are based on the value of the stock at date of transfer of the property. This value must be used when determining the profit or loss accruing to the individuals from the transaction, when determining depletion, depreciation, or invested capital of the corporation, or when determining the profit or loss arising from a subsequent sale of the assets of the corporation. The value of the stock can commonly be determined only by a valuation of the

assets; if these assets are oil properties, their value, as of date of acquisition by a corporation, may be required for any or all of the foregoing purposes.

Assets Acquired after March 3, 1917.—There is one important exception to the foregoing principles. The income tax regulations permit of no increase in the value of assets for invested capital purposes where reorganizations occur after March 3, 1917, provided 50 per cent or more of the control and ownership of the properties remains in the hands of the same persons.

Modifications under the 1921 Law.—The 1921 law, and rulings and regulations based thereon, follow the precedents established by the preceding laws respecting valuations at date of organization for purposes of determining depletion and depreciation, but there are some changes regarding the determination of profit and loss from the sale of capital assets. Under the 1921 income tax law no profit or loss arises from the transfer of an asset from an individual or group of individuals to a corporation, or from one corporation to another, provided the ownership and control remain, essentially, in the hands of the same persons. If the corporation then sells the property, the profit from the sale will be computed from the price paid by the previous owners rather than from the value of the property at the time it was acquired by the corporation.

At Date of Liquidation

In the liquidation of a corporation the creditors are satisfied first, and the stockholders receive the remaining assets in exchange for their stock. Liquidation under the income tax law is treated as if the stockholders sold their stock to the corporation for the assets which they receive; the sales price of the stock is the value of the assets. Where oil properties are received by the stockholders, valuations of these properties are required to determine the profit or loss to the stockholders arising from the liquidation. The individual stockholders, after receiving the assets of the corporation, will use the value of the assets as of date of liquidation as a basis for determining invested capital for the year 1917, for determining all future depletion and depreciation deductions, and profit and loss on any subsequent sale.

Inheritance or Gift

Under the Federal income tax laws, gifts received through inheritance, or in any other manner, are not taxable, but income from these gifts, as oil produced or interest earned, is subject to taxation. Assume that A receives a gift of $500,000 in cash and then purchases an oil property. When computing taxable income, depletion based on the cost of the property is deducted, the failure to deduct this depletion would subject the original amount of the gift, $500,000, to taxation. Similarly, if A receives an oil property whose value is $500,000, his depletion deductions would be based on the value of the property at the time he receives it.

Discovery Valuations

The development and application of geological science have greatly reduced the risks of the oil industry, but the drilling of wildcat wells will always be a hazardous venture. Until the well is completed, the owners cannot tell whether they have lost their entire investment or whether they have made a fortune. It is the hope of securing a large reward that induces men to invest in enterprises involving great risk, but if the profit from successful ventures is greatly reduced through high and progressive rates of taxation, the investor loses much of his reward and will be slower to accept risks in the future. The oil industry will suffer accordingly, as it demands the acceptance of great risks. Furthermore, as the profits from "wildcatting" occur in a short period of time, higher tax rates are applied than if the profit were distributed over a period of years. The discovery clauses were introduced into the Federal income tax laws to afford protection to the investor for the risks he assumes.

Legal Requirements.—Under the 1918 and 1921 income tax laws, depletion deductions may be based upon the value of the oil reserves within 30 days of discovery, provided (1) that the value of the property is disproportionate to cost, and (2) that the property was not acquired as the result of a proven tract. The discovery clause applies only to wells drilled after March 1, 1913. Definitions of a discovery well and discovery area are found in Regulations 45 and 62 of the United States Treasury Department. In a given pool or field, the first completed well whose value is disproportionate to its cost is a discovery well and

proves an area of 160 acres. The well is the center of this area, whose boundaries are north-south and east-west lines. Any well completed within a discovery area is not a discovery well nor does it extend the discovery area; but the first well drilled outside of a discovery area whose value is disproportionate to its cost is a discovery well. Exceptions to the above rule exist where a second owner is considered, or where production is obtained from a different sand; separate sets of discovery

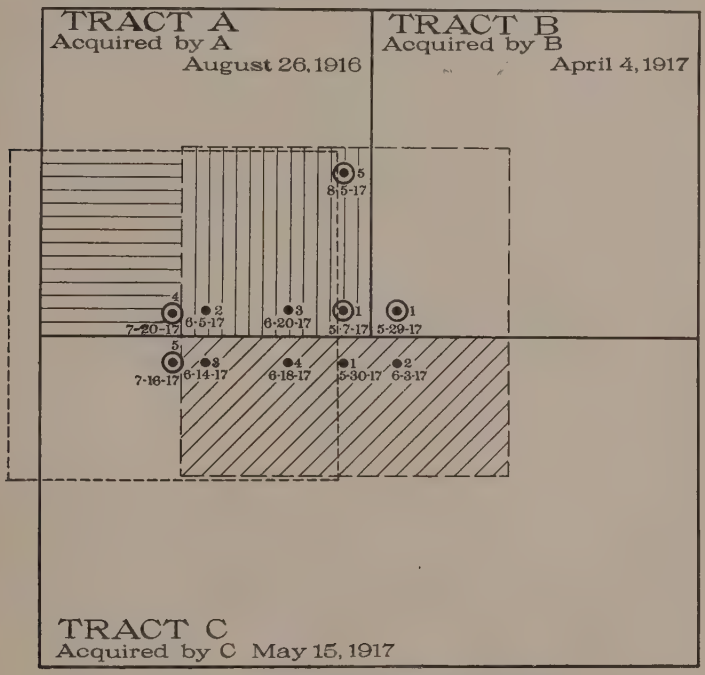

FIG. 41.—Diagram illustrating discovery areas.

areas exist for each owner of any interest in an oil property, and also for each oil sand.

Illustration of Discovery Wells.—Figure 41 illustrates the foregoing principles. A, B, and C own adjoining tracts of land; the dates the properties were acquired are indicated. Below each well is the date of completion, and all discovery wells are encircled. All wells are assumed to obtain their production from the same sand unless otherwise indicated, and the value of each

well is disproportionate to its cost. The first well was completed May 7, 1917, in the southeast corner of A's land. Obviously, this is a discovery well and proves 160 acres. The boundaries of the discovery area are indicated by the dashed lines. A is entitled to a discovery valuation on that portion of his property lying within the discovery area. This portion is indicated by the vertical ruling and contains approximately 50 acres. It is not until A drills outside of this discovery area that he is entitled to claim a second discovery. Well No. 4 is his second discovery well. The boundary of the discovery area is indicated by the dotted line. A is entitled to claim discovery valuations only on that portion of this area within his own boundary lines which is not included within the area previously discovered and upon which valuations have already been established. This portion is indicated by the horizontal ruling and contains approximately 40 acres.

Well No. 5 on A's land lies within the original discovery area but it is a discovery well because it obtains its production from a different sand.

Status of Development at Date of Acquisition.—The right to claim discovery is dependent upon the status of development at the time the property is acquired. No discoveries can be claimed upon that portion already proven at date of acquisition. At the time B acquired his land, April 4, 1917, no wells had been completed and he is entitled to claim discovery on his first well. When C acquired his land, well No. 1 on A's land had been completed and, consequently, that portion of C's land lying within the original dicovery area, indicated by the diagonal rulings, was proven when C acquired it. Therefore, C cannot claim discovery on this portion of his land, but must wait until he has completed a well outside this territory. Well No. 5 is his first discovery well.

Limitations of 1921 Law.—The 1921 law limits the amount of depletion which may be deducted under the discovery clause. The law provides:[1]

> That such depletion allowance based on discovery value shall not exceed the net income, computed without allowance for depletion, from the property upon which the discovery is made, except where such net income so computed is less than the depletion allowance based on cost or fair market value as of March 1, 1913 . . .

[1] Section 214 (a)-(10) of the 1921 law.

At Date of Sale

The use of discovery valuations in the computation of depletion protects the taxpayer who discovers oil and operates his property; but if he discovers oil and sells his property, he is protected in a different manner. Whenever a taxpayer proves that the chief value of his property is due to his activities in the discovery and development of that property, certain limitations are placed upon the tax arising from its sale. Under the 1918 law and for the year 1921, the surtax assessed individuals, and the war and excess profits tax assessed corporations, from the sale of such properties, shall not exceed 20 per cent of the selling price. Beginning with 1922, the surtax attributable to such sales shall not exceed 16 per cent of the selling price.

In a single transaction an operator may sell properties entitled to the above limitation and properties not entitled to it, necessitating the determination of profit arising from the sale of each class in order to make the proper application of the foregoing limitation. This can only be accomplished by a correct allocation of sales price between the two groups on the basis of sound valuations.

LEGAL EVIDENCE OF VALUE

The Value Sought

Whenever valuations are permitted or required under the Federal income tax laws they must be established "in the light of the conditions and circumstances known at that date, regardless of later discoveries or developments in the property, or subsequent improvements in methods of extraction and treatment of the oil and gas product. The value sought should be that established, assuming a transfer between a willing seller and a willing buyer as of that particular date." The Federal income tax laws and regulations prescribe the dates at which valuations are to be made, but the collection of evidence concerning value and the actual work of valuation may be, and usually is, postponed several years. Although the use of the discovery valuations as a basis for determining depletion deductions was not authorized until 1918, discoveries made in preceding years may be valued as of date of discovery or within 30 days thereafter; these valuations will then form the basis of determining depletion for 1918 and sub-

sequent years. If the taxpayer did not exercise this privilege at the time his return for 1918 (or any later year) was filed, he may prepare amended returns and file a claim for refund or credit, provided his claim has not been outlawed.

Types of Evidence

The value to be established is the "fair market value," and the following types of evidence may be used in its determination.[1]

1. Cost.
2. Actual sales and transfers of similar properties.
3. Market value of stock or shares.
4. Royalties and rentals.
5. Value fixed by the owner for purposes of the capital stock tax.
6. Valuations for local or state taxation.
7. Partnership accountings.
8. Records of litigation in which the value of the property was in question.
9. The amount at which the property may have been inventoried in probate court.
10. Disinterested appraisals by approved methods, such as the present value method.

Cost.—Normally the purchase price of a property constitutes the strongest evidence of its market value at that time. Only bona fide sales should be considered. There should be a change in beneficial interest, not merely in the legal form of the ownership; furthermore, abnormal sales, in which the sales price does not indicate the fair market value of the property, as forced sales, must be eliminated. Where valuations are required shortly after a purchase involving cash payments, the purchase price may be used. Adjustments, however, must be made for changes in the price of oil or in the development of the property, and allowance made for depletion and depreciation occurring between the date of purchase and the date of valuation.

Value of Stock.—The value of the properties of a company is sometimes reflected in the value of the stock, but, ordinarily, this value gives but little evidence of the actual value of the properties. Stock is sometimes subject to manipulation if held by many persons, and even more commonly it is bought and sold with but little knowledge of the properties or of the management

[1] Art. 206, Regulations 62, U. S. Treasury Department.

of the company. Stock held by only a few persons is seldom listed on the market, and as there are few sales its value cannot readily be determined.

Values for Taxation Purposes.—It is to the taxpayer's advantage to place low valuations upon his properties for purposes of state or local taxes and for inheritance or capital stock taxes, but if he undervalues his properties to avoid the payment of such taxes, these low valuations may become detrimental evidence if he claims excessive valuations for income tax purposes.

Present Value Method.—The present value method, discussed in the previous chapter, may be used where there is no better evidence of value. This method is the one most commonly employed.

CHAPTER XI

THE VALUATION OF GAS LANDS

Petroleum and natural gas are closely related geologically, frequently occurring in the same stratum. Many of the gas fields were discovered in the search for oil. Both minerals are commonly produced by the same company or by affiliated companies.

The chapters on The Value of Physical Equipment, Interest, Depletion and Depreciation, Methods of Valuation, and Valuation under the Federal Income Tax Laws, as well as portions of the chapters on Cost and Estimation of oil Reserves, apply with equal force, or with but slight modifications, to the valuation of gas lands. Only the distinctive features of the valuation of gas lands will be discussed.

GAS RESERVES

In many fields production records of individual wells or tracts cannot be obtained; a large number of wells may produce directly into the same pipe-line. Attempts to allocate the total metered production among the various wells and leases, on the basis of their relative capacity, are frequently handicapped through lack of adequate data. The estimation of gas reserves is further complicated by the irregularity of the performance of the individual wells. The amount and character of the data available determine which of the following methods should be employed in the estimation of gas reserves.

1. Production decline curves.
2. Saturation method.
3. Decline in rock pressure.
4. Decline in minute pressure.

Production Decline Curves

The regularity of decline in the production of oil wells has been attributed to the regularity in the decline of gas pressure. Consequently, it is logical to assume that if a gas well were allowed

to flow freely, there would be a greater regularity in the decline in output than in the case of oil wells, that this decline would more closely conform to mathematical laws, and that the future production would be more readily and accurately computed from the decline in past production.

Where gas is used for the manufacture of carbon black or for other industrial purposes where the demand is nearly constant, or where the entire output of a gas well can be used as soon as it can be extracted, the production may decline regularly. Production decline curve methods (see pp. 16 to 40) may then advisedly be used in the estimation of future production.

The output of gas wells conforms to the demand placed upon it, as gas cannot readily be stored, but must be used as rapidly as it is extracted. The demand for domestic purposes varies not only from season to season but from year to year in accordance with the weather conditions. Where there is a great irregularity in output the production decline curves cannot be used with any degree of accuracy.

Saturation Method

Application.—The saturation method (see pp. 71 to 76) is more commonly applied in estimating gas reserves than in estimating oil reserves. It is best applied to the estimation of the gas content of an entire pool rather than to the estimation of future production of individual wells, as cognizance is seldom taken of the peculiarities of individual wells or of their performance.

Factors Involved.—In addition to the factors of porosity, thickness of sand, extent of pool, relative saturation, and coefficient of recovery, which are the determining elements in the computation of oil reserves, the rock pressure and in some cases the temperature, must be considered when estimating the recoverable gas reserves. Where the gas is not dissolved in oil but exists in a free state, the relative saturation may usually be considered 100 per cent. Not all of the gas in the sand is exhausted, although the coefficient of recovery is very high as compared with oil. The encroachment of water may entrap some of the gas and prevent its recovery. Much of the gas extracted from the reservoir will not be utilized as the wastage is great.

Example.—Assume that a pool has an area of 10 square miles or approximately 280,000,000 square feet, that the average thickness of the sand is 20 feet and its porosity is 25 per cent.

The volume of the reservoir would be $\frac{280{,}000{,}000 \times 20}{4} =$ 1,400,000,000 cubic feet. If the rock pressure were 1,043 pounds, the gas contained in such a reservoir would be the equivalent of $\frac{1{,}400{,}000{,}000 \times 1{,}043}{0.5 + 14.4} = 98{,}000{,}000{,}000$ cubic feet at a pressure of 8 ounces above atmospheric pressure. Of this amount it may be estimated that 40 per cent or 39,200,000,000 cubic feet of gas will be utilized.

Correction for Temperature.—When estimating the content of deep gas reservoirs, corrections may in some instances be made for the temperature of the gas. The pressure which gas exerts depends upon its temperature and upon the amount of gas contained in a given space. Part of the rock pressure may be due to the increase in temperature with depth below the earth's surface. Allowance for temperature will result in reducing the estimate of gas within the reservoir. The amount of this correction will depend upon the depth of the reservoir and the temperature gradient. The temperature gradient varies from 1°F. in less than 20 feet to 1°F. in 130 feet. The average gradient has been considered as 1° in 50 to 60 feet, although this rate may be too high.[1]

Assuming a temperature gradient of 1° for 60 feet, a correction of approximately 6 per cent in volume at a depth of 1,000 feet is required. If the reservoir is 5,000 feet deep the volume of gas should be reduced 28 per cent. With other temperature gradients the correction may be more or less than that indicated. In some instances a reduction of 20 per cent to 25 per cent in volume may be required, but ordinarily the failure to make corrections for temperature is of little consequence.

Rock Pressure

According to Boyle's law the pressure exerted by the gas within a reservoir of a given size will vary in proportion to the amount of gas it contains, temperature remaining constant. Assume that gas is confined within a given reservoir or vessel at a pressure of 50 pounds per square inch and that one-half of the gas is allowed to escape, the pressure will then be 25 pounds. This principle is used in the estimation of gas reserves.

[1] Chamberlin, Thomas C., and Salisbury, Rollin D.: Geology, vol. 1, p. 569.

The decline in rock pressure is compared with the amount of gas produced. The original content of the gas reservoir is computed on the assumption that for each pound of decline in rock pressure an equal amount of gas will be produced.

Assume that the original gas pressure of a pool was 1,000 pounds and that the present pressure is 700 pounds, a decline of 300 pounds. Also assume that the total past production was 15,000,000,000 cubic feet or a production of 50,000,000 cubic feet for every pound decline in rock pressure. On the basis that the same relation will continue, the future production would be estimated as 700 × 50,000,000 cubic feet or 35,000,000,000 cubic feet, making a total production of 50,000,000,000 cubic feet.

Certain errors may arise in the strict application of this method as shown by the history of the McKeesport gas field. This field, which is barely a square mile in area, was discovered August 28, 1919. By December, 1920, there were 180 producing wells and 441 dry holes. Even with this close spacing the gas pressure apparently was poorly equalized in the early life of the field, as the decline in rock pressure of the individual wells greatly exceeded the rate of depletion of the field. During this period only 8 or 9 million cubic feet of gas were produced for each pound of decline in rock pressure. Later the yield was several times this amount for a similar decline. (See Column f, Table XII.)

Computations based on a strict application of Boyle's law (see Column g, Table XII) during the early life of the field are materially in error; the actual production (see Column h, Table XII) is twice as great as that indicated by Boyle's law. The foregoing discrepancies may be due in part to the rapid exhaustion of the field and in part to the unequal spacing of wells, but these discrepancies should serve as a warning against too close an adherence to the theoretical results obtained by this method. The method gives more accurate results in the later history of the field.

Rock pressure readings will give the most satisfactory results when the pressure throughout the field is uniform. This condition is ordinarily more nearly realized in the late summer or fall, after there has been a period of comparative idleness.

Decline in Open Flow Capacity and Minute Pressures.—Decline in open flow capacity and in minute pressure both serve as an index to the depletion of a gas well. If their decline and past production are known, the future production may be estimated

TABLE XII.—ESTIMATION OF RESERVES OF THE MCKEESPORT GAS FIELD BY MEANS OF BOYLE'S LAW[1]

(a) Month	(b) Number of producing wells at end of month	(c) Pressure at end of month in pounds per square inch	(d) Loss in rock-pressure during month in pounds per square inch	(e) Production in millions of cubic feet during month	(f) Millions of cubic feet produced during month for each pound decline in pressure (f = e ÷ d)	(g) Estimated number of billions of cubic feet of gas remaining in the ground at end of the month (g = f × (c + 14)	(h) Billions of cubic feet of gas produced after the end of the month (for comparison with g)
August, 1919	1	1,400[2]	...	.....	.....	...	18.0
September	2	1,165	235	1,440	6.13	7.2	16.6
October	4	950	215	1,620	7.54	7.3	14.9
November	8	740	210	2,034	9.7	7.3	12.9
December	12	535	205	1,926	9.4	5.2	11.0
January, 1920	28	320	215	1,980	9.2	3.1	9.0
February	38	244	76	1,566	20.6	5.3	7.4
March	59	185	59	1,278	21.7	4.3	6.2
April	89	133	52	936	18.0	2.6	5.2
May	117	105	28	774	27.6	3.3	4.4
June	142	90	15	594	39.6	4.1	3.9
July	155	80	10	612	61.2	5.8	3.2
August	166	60	20	576	28.8	2.1	2.7
September	185	50	10	414	41.4	2.6	2.2
October	184	40	10	396	39.6	2.1	1.9
November	177	20	20	306	15.3	0.5	1.5
December	180	10	10	288	28.6	0.7	1.3

[1] Compiled from data published by the Pennsylvania Bureau of Topographic and Geological Survey—Production of the McKeesport Gas Pool by J. French Robinson.

[2] The exact date of this reading is August 28, 1919, not August 31.

on the assumption that each cubic foot of gas extracted will exert an equal effect upon decline in minute pressure or in open flow capacity. The method is similar to the one preceding.

Assume the original minute pressure reading to have been 100 pounds and the present reading to be 70 pounds; a decline of 30 pounds evidently has occurred. If the production during the interval had been 1,200,000,000 cubic feet or 40,000,000 cubic feet for each pound of decline in minute pressure, the future estimated production would be 70 × 40,000,000 or 2,800,000,000 cubic feet of gas.

Yield of Gasoline

When gas is used in either absorption or compression plants for the extraction of gasoline, estimates may be required of the total gasoline content. The gasoline content of gas usually increases throughout the life of a well. The actual performance of similar wells with a longer period of production may be used as a basis for computing the importance of this factor. However, overestimates of the gasoline supply are a more common error than underestimates. More errors have probably been made in the overestimation of the available supply than in any other single factor in the gasoline industry.

Interference

A gas well in virgin territory may draw upon a large area, but as new wells are drilled part of the flow of gas is diverted to them. For this reason estimates based on a single well in a new territory are likely to be excessive and are indicative of the productivity of the pool rather than the individual well.

PRICE

The outstanding features controlling the field price of gas are (1) differences in composition, (2) the competition of other forms of fuel, (3) the distance to market and cost of marketing, (4) decline in supply, (5) long term contracts, and (6) control of price to the domestic consumer by public utility commissions. As a result of these factors the price in a given field is relatively stable, although subject to a slight increase from time to time, but the violent fluctuations which occur in oil prices are absent. Gas can be transported commercially only comparatively short distances,

due to excessive costs, consequently, both supply and demand are local in character. Great differences exist in the price of gas in the various fields. While a discussion of the price of gas must include the price paid by the consumer, only the field price can be used in the valuation of gas lands.

Composition

Natural gas consists essentially of methane, CH_4. The high heating value of natural gas is due largely to the presence of this compound and related hydrocarbons. Other compounds commonly occur in small amounts, and still others occasionally in large amounts as shown by the accompanying analyses. (See Table XIII.)

Analyses A, B, and C, showing the large amount of methane present and the varying amounts of other hydrocarbons, are typical, although the variations in the content of hydrocarbons, other than methane, is much greater than indicated from the

Table XIII.—Analyses of Natural Gas

Substance	Formula	A	B	C	D
Methane	CH_4	93.36	97.63	80.85	14.85
Other hydrocarbons	...	0.28	0.22	14.00	0.41
Carbon monoxide	CO	0.53	1.32	0.40	
Carbon dioxide	CO_2	0.25	0.22		
Hydrogen	H_2	1.76	.....	0.10	
Nitrogen	N_2	3.28	0.60	4.60	82.70
Helium	He	.....	.....	.....	1.84
Hydrogen sulphide	H_2S	0.18			
Oxygen	O_2	0.29	Trace	Trace	
Total	...	99.93	99.99	99.95	99.80

A. Mean of four gases from Indiana and three from Ohio, analyzed by C. C. Howard for the United States Geological Survey. Cited by W. J. McGee, Eleventh Ann. *Rep't.* U. S. Geol. Survey, pt. 1, 1891, p. 592.

B. From Osawatamie, Kansas. From a table of seven analyses by E. H. S. Bailey, Kansas Univ. Quart., vol. 4, 1895, p. 1.

Both of the above analyses are cited by F. W. Clark in The Data of Geochemistry, *Bull.* 695, U. S. Geol. Survey, p. 723.

C. Average gas from Pennsylvania and Ohio. Cited by Roy Cross, *Bull.* 15, Kansas City Testing Laboratory.

D. Helium-bearing gas from Dexter, Kansas. H. P. Cady and D. F. McFarland, *Jour. Am. Chem. Soc.*, 1907, p. 1530. Cited by Roy Cross in *Bull.* 15, Kansas City Testing Laboratory.

three analyses. This variation is of the greatest commercial significance as the gasoline content is found in these hydrocarbons and may materially increase the value of the gas. The amount of gasoline which can be extracted varies from 0 to 13 gallons per thousand cubic feet of gas.

The gas at Dexter, Kansas, is noted for its relatively high helium content, but even here the percentage of this element is low as shown by the accompanying analysis. (See D, Table XIII.) It should also be noted that the relatively high helium content is accompanied by high nitrogen content. Both gases are inert. Nitrogen decreases the heating value of gas and its presence in large quantities is detrimental. On the contrary, the great lifting power and inflammable character of helium render it very useful in "lighter than air" aircraft. Gas previously considered worthless because of its high nitrogen content may now be very valuable because of its high helium content.

Uses of Natural Gas

Natural gas has a variety of uses. One-third of the output is used in homes for cooking, lighting, and heating. Approximately one-fourth is used in the various industries, and nearly an equal portion is used in drilling and pumping oil wells. Seven per cent is manufactured into carbon black. The gasoline content was extracted from approximately two-thirds of the gas used for the above purposes in 1921. Only a minor amount is utilized for its helium content. The gas production in 1921 with its chief uses is given in the following table. Undoubtedly much more gas was wasted than is reported.

Table XIV.—Natural Gas Produced and Used in the United States in 1921[1]

	M cubic feet	Per cent of total
Gas produced	724,052,000	100
Gas used:		
Domestic consumption	248,334,000	34
Drilling and pumping	162,550,000	23
Carbon-black manufacture	50,565,000	7
Other industrial purposes	180,848,000	25
Gasoline extraction	479,618,000[2]	66
Reported waste	62,000,000	9

[1] Data compiled from Natural Gas in 1919–1921 by R. S. McBride and E. G. Sievers, Mineral Resources of the United States, 1921, Part II, pp. 339, 363.

[2] More than 95 per cent of the gas from which the gasoline content was extracted was later used for other purposes and is so reported.

Domestic Use.—Approximately 100 M cubic feet of gas were used by each domestic consumer in 1921. As contrasted with the industrial use for gas where the demand is nearly constant, there is a great seasonal variation in the amount of gas used for domestic purposes. The amount used in winter is several times the amount used in summer. Natural gas attains its highest usefulness when used for cooking. Its chief competitor in this field is artificial gas with a heating value less than that of natural gas and an average price twice as great.

Carbon-black Industry.—The chief item of cost in the manufacture of carbon black is the price paid for the gas consumed, consequently, the industry is located in fields where there is an abundant supply of cheap gas. At the present time (1923) the center of the industry is the Monroe gas field, Louisiana, where the price of gas is 2 cents to 3 cents per M cubic feet. The carbon-black industry is attracted to fields where a cheap supply of natural gas is available. This industry has been a great aid in the development of new fields where there has been little demand for gas for other purposes.

Gasoline Extraction.—Gasoline is now extracted from large quantities of gas but only a relatively small amount (less than 5 per cent of the total amount of the gas subjected to this process), is converted into gasoline. The remainder may be used for other purposes as the extraction of gasoline does not impair its usefulness.

There has been a rapid increase in the amount of gasoline extracted from natural gas. The utilization of leaner and leaner gas has been made possible through the introduction and growth of the absorption method of extraction. Compression plants seldom operate on a yield of less than 1 gallon of gasoline per thousand cubic feet of gas and the more common yields are 2 to 3 gallons per thousand cubic feet. Absorption plants may operate with gas which yields only 100 to 200 gallons per million cubic feet. Due to this utilization of leaner gas, the portion of the total reported gas production from which gasoline was extracted increased from less than ½ per cent in 1911 to 66 per cent in 1921, although the yield decreased from 3 gallons to less than 1 gallon per thousand cubic feet of gas.

Helium.—During the World War the chief weapons used against "lighter than air" aircraft were incendiary bullets. The inflammability of hydrogen made hydrogen-filled balloons very

vulnerable. Due to the inert and incombustible character of helium, balloons filled with this element were invulnerable against such attacks. Tragic accidents with hydrogen-filled balloons during times of peace have emphasized the importance of using helium. Only a few million cubic feet of helium have been extracted and the entire output has come from three government plants in Texas.

Supply

Relation to Demand.—The relation of supply to demand determines the price which gas can command. Natural gas commands a higher price for domestic use than when used industrially. The average price paid by domestic consumers in 1921 was 45 cents per M cubic feet as contrasted with an average price of 15 cents per M cubic feet paid by industrial consumers. The portion of gas used for domestic purposes varies greatly from field to field depending upon (a) the total available supply and (b) the amount used by domestic consumers. Where the supply is barely adequate to meet the demands of the domestic consumer high prices prevail. Prices are low where the supply is so great that its utilization depends upon the industrial market for consumption. As there are great differences between supply and demand of various localities, there are correspondingly great differences in prices.

Transportation.—Enormous costs are involved in the transportation of natural gas. For example, the cost of the proposed pipe-line from the Monroe gas field to New Orleans, a distance of 275 miles, is estimated to be 7½ million dollars. If the available supply is small, the cost of amortization is great per thousand cubic feet of gas transported. Estimates of available supply are thus required when computing cost of amortization.

The high cost of transportation affects both supply and demand. The demand for gas from a given field must come from within a limited area or the costs of transportation will be prohibitory; the available supply of a given locality is similarly restricted. The distance which natural gas can be transported is increased if use can be made of existing pipe-lines. A pipe-line system may be extended by additions from time to time. Thus, there has arisen a network of pipe-lines reaching from West Virginia east into Maryland, north into New York, and west into Kentucky and Indiana.

Field prices can most closely approach the price paid by the consumer when costs of transportation are slight, as transportation costs must be added to field prices. Assuming that the price paid by the consumer is determined in accordance with the preceding principles (or in any other manner), it is apparent that a great advantage is enjoyed by operators in fields located near centers of dense population, great industrial cities, or near existing pipe-lines.

Great costs may be involved even when gas is transported only short distances. The supply should be sufficient to meet operating expenses, amortize the investment and yield a fair return. The installation of gasoline plants is frequently delayed until the development of the field has assured an adequate supply.

Declining Supply.—After a field has been fully developed the decline in production is usually rapid. As production declines there is no corresponding decline in total costs, and increased prices are required to meet operating expense. The use of gas is confined more and more to those purposes to which it is best adapted. The typical price history in any field is one of relative stability accompanied by a slight increase from time to time. For this reason the method of price trends (see pp. 102, 103) may frequently be applied with good advantage in the prediction of gas prices.

Artificial Factors

Natural gas has been subjected to much legislation and regulation. The object has been either to conserve the supply for future needs or to regulate prices paid by the consumer. When it is effective, conservation legislation has changed the conditions of demand and supply either through prolonging future supply by a reduction in the waste, decreasing or increasing the present available output, or restricting the use of gas. In the Monroe gas field, Louisiana, the output of wells has been restricted to 20 per cent of the daily open flow capacity. Much of the effectiveness of this ruling is lost as it is unaccompanied by any regulations concerning the spacing of wells. Another regulation requires the extraction of the gasoline from the gas before it is used in the carbon-black plants. In many states the manufacture of carbon black has either been forbidden or severely restricted.

Companies distributing gas to domestic or industrial consumers are regarded as public utility corporations and the regu-

lation of gas rates by public service commissions may seriously modify the operation of the law of supply and demand. Public service commissions are usually slow to grant the increased rates required as the gas production declines. Gas companies must present their case in a fair and convincing manner to public service commissions and should enlist the support of an enlightened public. This requires a thorough knowledge of the broader phases of the industry as well as the details of their own business.

Long term contracts stipulating fixed prices have been required from the owners and operators of gas wells by gas companies as a protection against the slow advance in prices paid by the consumer. These contracts have been effective in stabilizing field prices, but at the same time they have led to a wide divergence in prices paid in the same field. Prices paid under new contracts are frequently much higher than those paid under old contracts.

COSTS

The cost of gas land, its development and operation is much less than similar expenditures for oil. Excessive bonuses paid for oil leases are seldom required when leasing gas lands. In many fields fixed rentals are paid for each commercial well instead of paying royalties on the gas produced.

Development costs for a tract of a given size are ordinarily much less on gas lands than on oil lands as the distance between wells is much greater. It has been estimated that on the average 40 acres are drained by each gas well and 5 acres by each oil well.[1]

When gas is supplied for domestic consumption it is necessary to have a number of wells in reserve to provide for the periods of peak load. The drilling of these additional wells necessitates an increased investment upon which a return will be greatly delayed.

Costs of operation and maintenance of gas wells are slight as compared with similar costs on oil wells. Ordinarily, only occasional repair work and blowing of wells is required.

Great costs, such as expenditures for pipe-lines, are connected with the gas industry, but these costs are not involved in the development and maintenance of gas lands themselves. They affect the valuation of gas lands only as they modify their availability.

[1] Shaw, Eugene Wesley: The Income and Expense of Natural Gas Production, Paper presented at the annual meeting of The Natural Gas Association of America, May, 1920.

DEPLETION

With the exception of applying different units, the same methods of depletion and depreciation can be applied to gas properties as are applied to oil properties. The depletion unit for oil properties is the barrel, for gas properties either M cubic feet or the pound of rock pressure may be employed.

Without estimating the gas reserves, a well with an initial rock pressure of 1,000 pounds may be considered half exhausted when the pressure has declined to 500 pounds. In applying this method it is necessary to determine the ratio between (1) the decline in rock pressure during a given period and (2) the sum of the rock pressures at the beginning of the period, plus the sum of the initial rock pressures of wells drilled during this period. This ratio is then applied against the amount subject to depletion.

An example will illustrate this method. On January 1, 1923, the rock pressures of a group of wells was 1,000 pounds, 850 pounds, and 200 pounds. On May 5, 1923, a new well was drilled which had an initial rock pressure of 950 pounds. The sum of these pressures is 3,000 pounds. During the year one well was abandoned. The rock pressures of the other three wells at the end of the year were 650, 750 and 400 pounds, or a total of 1,800 pounds. The decline is 1,200 pounds. If $60,000 represents the sum subject to depletion, the amount of depletion would be $\frac{1,200}{3,000} \times \$60,000$ or $24,000.

Certain adjustments may be required when the rock pressure of a well is small. Assume that a well with an initial rock pressure of 100 pounds will be abandoned when the pressure has declined to 25 pounds. Approximately 25 per cent of the original gas content will remain in the ground when the well is abandoned and only 75 per cent will be recovered. When the rock pressure has declined 50 pounds, 50 per cent of the original gas content has been recovered but this amount represents more than one-half of the recoverable reserves. If only 75 per cent is recoverable and 50 per cent has been recovered, the amount of depletion is $^{50}/_{75}$ per cent or two-thirds.

When computing depletion the pound pressure may be used as the depletion unit but it is usually advisable to employ M cubic feet whenever gas reserves can be determined and production records are available.

APPENDIX

LOGARITHMIC COORDINATES OF PRODUCTION-DECLINE CURVES

The following table is from the "Manual for the Oil and Gas Industry" of the United States Treasury Department and gives the coordinates on logarithmic paper of production-decline curves for various fields.

The first column gives the states and counties, arranged alphabetically, in which the pools or districts are located.

The second column gives the pool or district.

The third column gives the sand or sands upon which the curves were based. *The tables and curves . . . should not be used to estimate reserves for other sands than those given in this column.*

Columns four to seven give the X and Y coordinates used to establish two points for each production-decline curve, which is to be plotted as a straight line on logarithmic paper.

Unless noted under "Remarks," all coordinates are for yearly production-decline curves.

TABLE XV.—TABLE SHOWING X AND Y VALUES OF PRODUCTION-DECLINE CURVES FOR VARIOUS POOLS AND DISTRICTS

County	Pool or district	Sand or formation to which curve is applicable	X_1	Y_1	X_2	Y_2	Remarks
California:							
Fresno	East Side Coalinga pool.	First, second, or both zones.	18	90,000	38	1,200	
	West Side Coalinga pool.	Any or all zones.	18	95,000	42	1,000	
Kern	Belridge pool.	Upper zone.	10	28,000	24	1,000	
	East Side Elk Hills district, secs. 35, 36, T. 30 S., R. 24E.; sec. 31, T. 30S., R. 25E.	First zone.	2	1,000,000	6	10,000	Does not apply to West Side Elk Hills.
	Kern River pool.	Thick zone.	15	42,400	38	1,250	Sustained curve due to use of sustained tract production.
	Lost Hills pool.	First or second zone.	12	52,000	26	1,000	For spacing of 4 to 5 acres per well.
	McKittrick pool.	Wells producing from different and several zones.	4	49,500	37	1,000	Sustained curve due to complex structure and great difference in number of productive sands from different wells; also to use of sustained tract production.
	Midway-Sunset district, Buena Vista Hills area.	Either or both zones.	7	800,000	14	14,500	Applies to drilled-up area only.
	Midway-Sunset district, Fellows area.	Any or all zones.	20	100,000	34	1,200	
	Midway-Sunset district, Maricopa Flat area.	First zone.	10	27,500	29	1,000	
	Midway-Sunset district, sec. 15, T. 31S., R22E.	First zone.	9	30,000	33	1,000	
	Midway-Sunset district, Twenty-five Hill area.	Either or both zones.	4	37,000	26	1,000	

Los Angeles	Montebello pool.	Upper zone (first).	4	62,800	22	1,000
		Lower zone (second).	5	700,000	11	10,000
	Salt Lake pool.	Puente formation.	39	90,000	56	1,000
Los Angeles and Orange	West Coyote pool.	Any or all sands.	9	530,000	16	10,500
Los Angeles	Whittier pool.	Any or all sands.	50	78,000	66	1,200
Orange	Brea Canyon pool.	Any sand.	13	400,000	24	11,000
	Fullerton, La Habra pool.	Any or all sands.	8	72,000	25	1,000
	Olinda pool.	Any or all sands.	38	75,000	58	1,100
Orange and Los Angeles	West Coyote pool.	Any or all sands.	9	530,000	16	10,500
Santa Barbara	Santa Maria pool.	Deep zones only.	28	75,000	41	1,100
Ventura	Shields Canyon pool.	Upper sand.	1	20,000	9	1,000
Illinois:						
Clark	Johnson pool.	Either of two pay sands in Casey sand.	6	10,000	19	125
	Westfield pool.	Either of two pay sands in Casey sand.	2	2,200	10	129
Clinton and Marion	Carlyle and Sandoval pools.	Stein, Benoist, or Carlyle sand.	51	3,200	64	100
Crawford	Birds-Flatrock district.	Robinson sand.	7	7,900	19	115
	Robinson and other pools.	Robinson and Kirkwood sands.	20	10,000	31	125
Cumberland	Siggins pool.	Either of two pay sands in Casey sand.	4	4,300	27	100
Lawrence	Dennison pool.	Bridgeport, Ridgely, Kirkwood, Tracy, or McClosky sands.	11	6,100	24	110
	Kirkwood pool.	Kirkwood, Tracey, or McClosky sands.	51	8,000	63	100
	Upper Lawrence district.	Bridgeport, Kirkwood, Tracey, or McClosky sands.	26	10,000	40	110
Marion and Clinton	Sandoval and Carlyle pools.	Either Stein, Benoist, or Caryle sands.	51	3,200	64	100
McDonough	Plymouth or Comar pool.	Hoing sand.	13	900	17	50

TABLE XV.—*Continued*

County	Pool or district	Sand or formation to which curve is applicable	X_1	Y_1	X_2	Y_2	Remarks
Indiana:							
Adams, Blackford and Jay	Blackford and other pools.	Trenton limestone.	8	835	21	35	
Blackford, Jay and Adams	Blackford and other pools.	Trenton limestone.	8	835	21	35	
Gibson	Princeton.	Princeton sand.	21	835	32	50	
Grant	Northeast quarter of Grant County.	Trenton limestone.	50	1,500	58	100	
Huntington	Southern part of Huntington County.	Trenton limestone.	31	760	42	35	
Jay, Adams, and Blackford	Blackford and other pools.	Trenton limestone.	8	835	21	35	
Pike	Petersburg, Gladish, Bowman, Rumble, and Oakland City.	Rumble, Gladish, and Oakland City.	10	5,500	16	180	
Sullivan	Sullivan.	Two sands in the Huron formation.	8	6,000	16	100	
Kansas:							
Butler	Augusta district.	Either of several sands.	3	100,000	8	1,200	
	Eldorado district.	Either of several sands.	4	83,000	9	1,100	
Butler and Marion	Peabody-Elbing district.	Sands of Mississippian age.	19	100,000	24	1,050	Quarterly production curve.
Chautauqua and Montgomery.	Chautauqua-Sedan district.	Bartlesville, Peru, and Red Fork sands.	4	2,150	15	125	
Marion and Butler	Peabody-Elbing district.	Sands of Mississippian age.	19	100,000	24	1,050	Quarterly production curve.
Montgomery and Chautauqua.	Chautauqu-Sedan district.	Bartlesville, Peru, and Red Fork sands.	4	2,150	15	125	
Wilson	Neodesha district.	Cherokee shale.	5	520	31	75	

Kentucky:						
Bath	Ragland district.	Corniferous.	7	3,700	23	100
Estill	Irvine pool.	Corniferous.	25	5,200	33	100
Floyd	Beaver pool.	Any of several Carboniferous sands.	10	2,750	25	160
Wayne	Mount Pisgah, Sinking, Slickford, and Parnell pools.	Beaver Creek sand.	3	2,600	11	150
Louisiana:						
Acadia	Evangeline-Jennings pool.	Salt dome.	6	41,000	18	1,000
Caddo	Mooringsport pool.	Woodbine sand.	9	35,000	19	1,000
	Pine Island pool.	Woodbine sand.	3	100,000	5	2,000
	Vivian pool.	Woodbine sand.	4	27,000	7	1,050
Calcasieu	Edgerly pool.	Salt dome.	2	37,000	8	1,000
	Vinton pool.	Salt dome.	2	37,500	10	1,000
DeSota	DeSota district.	Woodbine sand.	4	65,000	11	1,250
Red River	Red River district.	Woodbine sand.	2	75,000	9	1,125
New York:						
Allegany and Cattaraugus, N. Y., and McKean County, Pa	Several pools.	Bradford.	9	7,880	32	100
Ohio:						
Allen	Lima district.	Trenton limestone.	5	920	20	35
Belmont, Jefferson, and Monroe	Several pools.	Berea.	9	700	23	40
Jefferson, Monroe, and Belmont	Several pools.	Berea.	9	700	23	40
Hancock	Lima district.	Trenton limestone.	9	940	30	35
Hocking and Perry	Gore pool.	Clinton.	2	6,300	10	200
Lucas and Ottawa	Lima district.	Trenton limestone.	3	730	21	35
Mercer	Lima district.	Trenton limestone.	3	640	20	35
Monroe, Belmont, and Jefferson	Several pools.	Berea.	9	700	23	40
Monroe	Jackson Ridge pool.	Keener.	10	1,500	28	102

TABLE XV.—*Continued*

County	Pool or district	Sand or formation to which curve is applicable	X_1	Y_1	X_2	Y_2	Remarks
Ottawa and Lucas	Lima district.	Trenton limestone.	3	730	21	35	
Perry and Hocking	Gore pool.	Clinton.	2	6,300	10	200	
Sandusky	Lima district.	Trenton limestone.	2	4,200	14	110	
Seneca	Lima district.	Trenton limestone.	21	780	35	35	
Van Wert	Lima district.	Trenton limestone.	3	690	20	35	
Washington	St. Mary's pool.	Keener.	10	1,120	18	100	
Wayne	Several pools.	Clinton.	9	7,500	15	200	
Wood	Lima district.	Trenton limestone.	3	8,600	17	100	
Oklahoma:							
Carter	Healdton district.	Healdton or deeper sand.	40	53,000	49	1,000	
	Hewitt pool.	Upper Hewitt sand.	15	58,000	20	1,550	Quarterly production curve.
Creek	Cushing pool.	Bartlesville sand.	3	100,000	9	1,200	
	Cushing pool.	Layton sand.	2	22,500	6	1,025	
	Cushing pool.	Tucker sand.	2	100,000	7	2,000	
	Cushing pool.	Wheeler sand.	11	41,000	15	1,100	
Creek and Tulsa	Glenn pool.	Glenn sand.	10	54,000	18	1,100	
	Glenn pool.	Red Fork sand.	2	9,300	17	103	
	Glenn pool.	Taneha sand.	10	9,700	21	100	
Garfield	Garber pool.	Any of a number of sands.	3	75,000	6	1,000	
Kay	Blackwell district.	Any of several deep sands.	2	8,900	9	103	
Muskogee	Muskogee-Boynton district.	Any of a number of sands.	5	5,600	12	105	
Nowata	Adair pool.	Bartlesville sand.	2	3,000	10	110	
Nowata and Rogers	Nowata district.	Bartlesville sand.	4	4,550	13	140	
Okmulgee	Okmulgee district.	Any of a number of sands.	3	40,000	9	1,080	
Osage and Washington	Avant-Ramona district.	Bartlesville sand.	11	60,000	20	1,250	
Osage	Hominy district.	Either Peru, Oswego, or Bartlesville sand.	8	85,000	16	1,250	
	Okesa district.	Bartlesville sand.	5	9,000	26	120	
	Pawhuska-Wynona district.	Either Peru or Bartlesville sand.	5	82,000	13	1,150	

Osage and Tulsa	Bird Creek-Skiatook district.	Bartlesville sand.	9	9,800	23	150
Pawnee	Cleveland district.	Cleveland, Bartlesville or Tucker sand.	6	9,100	21	200
Rogers and Nowata	Nowata.	Bartlesville sand.	4	4,550	13	140
Tulsa and Osage	Bird Creek-Skiatook district.	Bartlesville sand.	9	9,800	23	150
Tulsa and Creek	Glenn.	Glenn sand.	10	54,000	18	1,100
	Glenn.	Red Fork sand.	2	9,300	17	103
	Glenn.	Taneha sand.	10	9,700	21	100
Washington and Osage	Avant-Romona district.	Bartlesville sand.	11	60,000	20	1,250
Washington	Bartlesville-Dewey district.	Bartlesville sand.	3	100,000	11	1,000
	Bartlesville-Dewey district.	Peru.	3	10,000	12	175
Pennsylvania:						
Allegheny	Dorseyville, Grafton, and Chartiers pools.	Thirty-foot sand.	2	5,000	13	115
	Fort Pitt, Grafton, and Chartiers.	Gordon sand.	10	1,200	28	100
Allegheny and Butler	Brush Creek, Milltown, Glade Run, Slippery Rock and other pools.	One hundred-foot sand.	10	2,000	28	103
Allegheny and Washington.	McDonald, Venice, Grafton, Washington, and other pools.	Fifth sand.	3	2,700	20	100
Butler	Speechly pool.	Speechly sand.	10	1,700	25	150
Butler and Allegheny	Glade Run, Slippery Rock, Brush Creek, Milltown, and other pools.	One hundred-foot sand.	10	2,000	28	103
Greene	Ninevah and Cameron.	Gordon sand.	3	8,600	21	130
McKean, Pa., and Cattaraugus and Allegany Counties, N. Y.	Several pools.	Bradford sand.	9	7,880	32	100
Washington and Allegheny.	McDonald, Venice, Grafton, Washington, and other pools.	Fifth sand.	3	2,700	20	100

TABLE XV.—*Continued*

County	Pool or district	Sands or formation to which curve is applicable	X_1	Y_1	X_2	Y_2	Remarks
Texas:							
Eastland	Desdemona pool.	Ranger sand.	10	58,000	12	1,900	Quarterly production curve.
	Ranger district.	Ranger sand.	5	66,000	10	1,000	Quarterly production curve.
Hardin	Batson pool.	Salt dome.	6	33,000	16	1,000	
	Sour Lake pool.	Salt dome.	11	50,000	17	1,000	
	Saratoga pool.	Salt dome.	10	62,000	20	1,000	
Harris	Goose Creek pool.	Salt dome.	3	68,000	7	1,000	
	Humble pool.	Salt dome.	3	57,000	6	1,000	
Jefferson	Spindle Top pool.	Salt dome.	3	40,000	12	1,000	
Marion	Western extension, Caddo, La., district.	Woodbine sand.	3	52,000	11	1,200	
Navarro	Corsicana pool (light oil).	Powell sand.	10	4,800	30	130	
	Corsicana pool (heavy oil).	Nacatoch sand.	10	4,700	23	112	
Palo Pinto	Old Strawn (shallow pool).	Strawn formation.	2	1,900	6	110	
Stephens	Caddo-La Casa district.	Caddo limestone.	43	70,000	49	1,000	Quarterly production curve.
	Parks-Breckenridge district.	Caddo limestone.	36	94,800	50	1,100	Quarterly production curve.
Wichita	Burkburnett Old Field pool.	Wichita sand.	3	35,000	10	1,440	
	Burkburnett northwestern pool.	Wichita sand.	4	40,000	8	1,450	Quarterly production curve.
	Burkburnett town site pool.	Wichita sand.	2	3,850	6	500	Quarterly production curve.
Wichita and Wilbarger	Electra district.	Wichita formation.	11	37,000	17	1,300	
Wilbarger and Wichita	Electra district.	Wichita formation.	11	37,000	17	1,300	
West Virginia:							
Dodridge	Shiveley and Salem pools.	Gordon sand.	20	2,100	34	100	
Gilmer and Lewis	Maxon, Buffalo, Fink, and Carter pools.	Gordon, Fifth, and Fifty-foot sand.	5	2,820	16	115	

Harrison	Eagle, Clay, and Salem pools.	Gordon sand.	18	1,900	30	125
	Shinnston pool.	Fifty-foot sand.	3	6,200	12	110
Lewis and Gilmer	Maxon, Buffalo, Fink, and Carter pools.	Gordon, Fifth, and Fifty-foot sand.	5	2,820	16	115
Lincoln	Duval pool.	Berea sand.	5	9,700	17	150
Roane	Spencer, Rock Creek, Harper, and others.	Big Injun sand.	25	3,200	38	105
Wetzel	Four-Mile, Wetzel, and Folsom pools.	Gordon sand.	20	4,100	31	110
Wyoming:						
Converse	Big Muddy pool.	First Wall Creek sand.	10	85,000	17	1,400
Hot Springs	Grass Creek pool.	Frontier formation.	40	24,900	44	1,200
Natrona	Salt Creek pool.	First Wall Creek sand.	13	96,000	24	1,400
Park	Elk Basin pool.	Frontier sand.	20	77,000	26	1,000

RATE OF DEPRECIATION

Extract from the "Manual for the Oil and Gas Industry" Published by the United States Treasury Department

The percentages and tables included in this paper are intended as a *suggestion* for the guidance of the taxpayer in calculating his just tax. The percentages are neither maximum nor minimum rates. They are *not to be applied indiscriminately to specific property*, and the Internal Revenue Bureau is in no way committed to accept allowances based upon them. Every claim for deduction must be accompanied by a detailed statement of the facts upon which such claim is based.

Each class of equipment is shown in detail and as a class, with the suggestion that an average life of the class be used rather than the life of any individual part.

. . . . . .

It must be borne in mind that it is not possible to make standard rules or formulas to cover all conditions in the oil and gas industry.

Although different rates may reasonably be applied in different parts of the country, the average rates for each locality have not been included here, as it is believed that the variation of such rates from the general average is so slight as to be practically negligible in most instances. Whenever the life of the property is materially shorter than that called for in this schedule, a special rate may be claimed, or the differences may be made up by replacements chargeable to the maintenance accounts. In the case of some of the Gulf Coast districts, portions of the pipe lines are eaten out in 5 or 6 years. These repairs are rightly a replacement and chargeable to maintenance or operating accounts.

. . . . . .

Class A, No. 1.—Drilling Equipment

This includes engines, boilers, rig irons, and portable derricks.

It is recommended that 4 years' life be allowed to equipment as a whole, depreciated at the following rate:

	Per Cent
First year	40
Second year	25
Third year	15
Fourth year	10
	90
Salvage	10
	100

Permanent derricks, rig irons, boilers, and engines left at the well are included under "Well equipment."

Drilling tools (cable and rotary) and fishing tools are included under "Tools"—Class A, No. 5.

Class A, No. 2.—Well Equipment

As most equipment of a producing well *has no separate value apart from the well*, it is suggested that all wells and their equipment be depreciated at the same rate as the wells are *depleted*, using the same curve rate for both; but if the life of the physical equipment is greater than the life of the deposit, then the depreciation rate of the physical equipment will be governed by the reasonable expectation of the life of the deposit.

If the life of the equipment is shorter than the life of the well, then replaced equipment should be charged against maintenance and operation.

This method proved satisfactory in the appraisements of the Independent Oil Producers' Agency of California, embracing some 130 companies, and is generally acceptable to all operators who have been consulted in the matter.

Class A, No. 3.—Dehydrators

These are either of electric, pipe, or tank type. The life of the pipe and tank dehydrators is very erratic as these burn out quickly with practically no salvage. It is recommended that this type of equipment have a straight-line depreciation as follows:

	Life, years	Depreciation per annum, per cent
Electric	5	20
Pipe	2	50
Tank	2	50

Class A, No. 4.—Tanks

The following depreciation rate for tanks is recommended:

	Life, years	Per cent
Steel, 5,000 to 55,000 barrels	20	5
Steel, 2,500 to 5,000 barrels	12	8⅓
G. I., 500 to 2,500 barrels	12	8⅓
G. I., less than 500 barrels	8	12½
Wood	5	20
Movable tanks:		
G. I., 500 to 2,500 barrels	9	11⅑
G. I., less than 500 barrels	6	16⅔
G. I., water tanks, 500 to 2,500 barrels	8	12½
G. I., water tanks, less than 500 barrels	5	20

These results may be used for all classes of service, that is, oil producing, refineries, etc.

Class A, No. 5.—Tools

This includes standard, rotary, and fishing tools. While rotary equipment may be shorter lived, it is, in general, offset by the standard tool equipment which will have a life of at least 4 years in many cases.

Owing to the excessive wear and tear and losses on such equipment, an average life of 3 years is recommended, using an annual depreciation rate of 33⅓ per cent.

Class A, No. 6.—Transportation Equipment

All transportation equipment, such as motor trucks, autos, wagons, horses, and harness, can be placed at a 3-year life or an annual depreciation rate of 33⅓ per cent.

In fact, the average life of automobiles is less than 3 years. The percentages of cost for horses, harness, and wagons are such that they can be grouped with 3 years' life, disregarding salvage value.

Class A, No. 7.—Water Plants

Considering the water well, pump, steam power, gas and oil power, and electric power as a class, they may be given a useful life of approximately 10 years, allowing a straight depreciation rate of 10 per cent.

Class A, No. 8.—Electric Equipment

In considering electrical equipment, one may include the separate items of generators, motors of various sizes, transformers, wiring (both indoor and outdoor), power lines, and switchboard.

As oil-well motors are not suitable for other uses and as the class of wiring usually done on leases is not up to utility company standards, it is recommended that a combined life on electric equipment be placed at 10 years, allowing a depreciation rate of 10 per cent.

Class A, No. 9.—Machine Shop

In covering machine shop there are included wood buildings, power tools, blacksmith tools, small hand tools, shafting, and shop power, which will, on an average, have a 7-year life or a depreciation rate of 14⅜ per cent. The smaller hand tools, of course, may have a life of not more than 2 years, but their cost is not important and the depreciation rate is lowered by the longer life of more expensive items, such as power tools, wood buildings, shafting, and power equipment.

Class A, No. 10.—Buildings

Buildings are grouped into four classes:

No. 1, wood, which includes small dwellings, small outhouses, small warehouses, small power plants, and small platforms which are built on the ground. These have an average life of 10 years, which allows a depreciation rate of 10 per cent.

No. 2, frame buildings, placed on brick or concrete foundation with siding and shingle or patent roof painted, have an average life of 15 years, or a straight-line depreciation rate of 6⅔ per cent.

No. 3, corrugated iron siding, renewable, has a life of 6 years, or a depreciation rate of 16⅔ per cent.

No. 4, concrete, brick, and steel frame have an average life of 25 years, or an annual depreciation rate of 4 per cent.

The permanent buildings may outlast the remainder of the plant, hence have no salvage value. Gulf Coast fields may claim shorter life for iron buildings because of salt air conditions.

Class B.—Pipe Lines

Pipe lines are subdivided into main line, pump stations (which include all equipment, such as engines, pumps, boilers, etc.), auxiliary equipment, buildings, telephone and telegraph, and terminal facilities.

It is recommended that—

Mains 6 inches or over in diameter be based on a 20-year life, or an annual depreciation rate of 5 per cent.

Mains under 6 inches in diameter be based on a 16-year life, or an annual depreciation rate of 6¼ per cent.

Gathering lines be based on a 10-year life, or an annual depreciation rate of 10 per cent, with a salvage of 10 per cent.

Pump stations, including all equipment, telephone lines, and terminal facilities, based on a life of 10 years, or an annual depreciation rate of 10 per cent.

These conclusions were reached after carefully considering detailed data in which it was decided that pipe lines could be grouped into the subdivisions given above.

The subject of electrolysis in pipe lines has been investigated and the losses have proved to be very small and negligible in comparison with the amounts invested, so far as making any special allowances in depreciation.

Below is given the result of a pipe line 220 miles long, having 16 stations and costing $3,906,668:

	Cost	Per cent of total cost	Life in years	Weight
Right of way	$ 83,176	2.2	20	0.44
Ditching	497,358	12.7	20[1]	2.54
Pipe	1,323,901	33.9	20	6.78
Steel storage	426,047	10.9	20	2.18
Buildings	246,651	6.3	20	1.26
Total	$2,577,133			
Machinery:				
Pumps	$ 260,108	6.7	14	0.94
Boilers	136,356	3.5	10	0.35
Heaters	30,341	0.8	10	0.08
Miscellaneous (freight, etc.)	88,937	2.3	8	0.18
Total	$ 515,742			
Wiring	$ 8,060	0.2	10	0.02
Fittings	151,725	3.9	7	0.27
Commissary	270,782	6.9	10	0.69
Telephone lines	85,905	2.2	10	0.22
Spurs, loading racks, etc	14,276	0.4	5	0.02
Sundries (tools, paints, water wells, etc., superintendence supervision)	283,045	7.2	5	0.36
Total	$1,329,535	100.1	. .	16.33[2]
Grand total cost	$3,906,668			

[1] Same as pipe.

[2] Average life in years.

VALUATION AND INTEREST TABLES

TABLE XVI.—PRESENT VALUE OF $1 DUE $\frac{2n-1}{2}$ YEARS HENCE AT THE FOLLOWING RATES OF INTEREST COMPOUNDED SEMI-ANNUALLY

Years	5 %	6 %	7 %	8 %	9 %	10 %	12 %	15 %	20 %	25 %	30 %	Years
1	.9756	.9709	.9662	.9615	.9569	.9524	.9434	.9302	.9091	.8889	.8696	1
2	.9286	.9151	.9019	.8890	.8763	.8638	.8396	.8050	.7513	.7023	.6575	2
3	.8839	.8626	.8420	.8219	.8025	.7835	.7473	.6966	.6209	.5549	.4972	3
4	.8413	.8131	.7860	.7599	.7348	.7107	.6651	.6028	.5132	.4385	.3759	4
5	.8007	.7664	.7337	.7026	.6729	.6446	.5919	.5216	.4241	.3464	.2843	5
6	.7621	.7224	.6849	.6496	.6162	.5847	.5268	.4513	.3505	.2737	.2149	6
7	.7254	.6810	.6394	.6006	.5643	.5303	.4688	.3906	.2897	.2163	.1625	7
8	.6905	.6419	.5969	.5553	.5167	.4810	.4173	.3380	.2394	.1709	.1229	8
9	.6572	.6050	.5572	.5134	.4732	.4363	.3714	.2925	.1978	.1350	.0929	9
10	.6255	.5703	.5202	.4746	.4333	.3957	.3305	.2531	.1635	.1067	.0703	10
11	.5954	.5375	.4856	.4388	.3968	.3589	.2942	.2190	.1351	.0843	.0531	11
12	.5667	.5067	.4533	.4057	.3634	.3256	.2618	.1895	.1117	.0666	.0402	12
13	.5394	.4776	.4231	.3751	.3327	.2953	.2330	.1640	.0923	.0526	.0304	13
14	.5134	.4502	.3950	.3468	.3047	.2678	.2074	.1419	.0763	.0416	.0230	14
15	.4887	.4243	.3687	.3207	.2790	.2429	.1846	.1228	.0630	.0329	.0174	15
16	.4651	.4000	.3442	.2965	.2555	.2204	.1643	.....	.....	.....	.....	16
17	.4427	.3770	.3213	.2741	.2340	.1999	.1462	.....	.....	.....	.....	17
18	.4214	.3554	.3000	.2534	.2143	.1813	.1301	.....	.....	.....	.....	18
19	.4011	.3350	.2800	.2343	.1962	.1644	.1158	.....	.....	.....	.....	19
20	.3817	.3158	.2614	.2166	.1797	.1491	.1031	.....	.....	.....	.....	20
21	.3633	.2976	.2440	.2003	.1645	.1353	.0917	.....	.....	.....	.....	21
22	.3458	.2805	.2278	.1852	.1507	.1227	.0816	.....	.....	.....	.....	22
23	.3292	.2644	.2127	.1712	.1380	.1113	.0727	.....	.....	.....	.....	23
24	.3133	.2493	.1985	.1583	.1263	.1009	.0647	.....	.....	.....	.....	24
25	.2982	.2350	.1853	.1463	.1157	.0916	.0575	.....	.....	.....	.....	25
26	.2838	.2215	.1730	.1353	.1059	.0831	.0512	.....	.....	.....	.....	26
27	.2702	.2088	.1615	.1251	.0970	.0753	.0456	.....	.....	.....	.....	27
28	.2572	.1968	.1508	.1157	.0888	.0683	.0406	.....	.....	.....	.....	28
29	.2448	.1855	.1407	.1069	.0814	.0620	.0361	.....	.....	.....	.....	29
30	.2330	.1748	.1314	.0989	.0745	.0562	.0321	.....	.....	.....	.....	30

TABLE XVII.—PRESENT VALUE OF $1 DUE n YEARS HENCE AT THE FOLLOWING RATES OF INTEREST COMPOUNDED SEMI-ANNUALLY

Years	5 %	6 %	7 %	8 %	9 %	10 %	12 %	15 %	20 %	25 %	30 %	Years
1	.9518	.9426	.9335	.9246	.9157	.9070	.8900	.8653	.8264	.7901	.7561	1
2	.9060	.8885	.8714	.8548	.8386	.8227	.7921	.7488	.6830	.6243	.5718	2
3	.8623	.8375	.8135	.7903	.7679	.7462	.7050	.6480	.5645	.4933	.4323	3
4	.8207	.7894	.7594	.7307	.7032	.6768	.6274	.5607	.4665	.3897	.3269	4
5	.7812	.7441	.7089	.6756	.6439	.6139	.5584	.4852	.3855	.3079	.2472	5
6	.7436	.7014	.6618	.6246	.5897	.5568	.4970	.4199	.3186	.2433	.1869	6
7	.7077	.6611	.6178	.5775	.5400	.5051	.4423	.3633	.2633	.1922	.1413	7
8	.6736	.6232	.5767	.5339	.4945	.4581	.3936	.3144	.2176	.1519	.1069	8
9	.6412	.5874	.5384	.4936	.4528	.4155	.3503	.2720	.1799	.1200	.0808	9
10	.6103	.5537	.5026	.4564	.4146	.3769	.3118	.2354	.1486	.0948	.0611	10
11	.5809	.5219	.4692	.4220	.3797	.3418	.2775	.2037	.1228	.0749	.0462	11
12	.5529	.4919	.4380	.3901	.3477	.3101	.2470	.1763	.1015	.0592	.0349	12
13	.5262	.4637	.4088	.3607	.3184	.2812	.2198	.1525	.0839	.0468	.0264	13
14	.5009	.4371	.3817	.3335	.2916	.2551	.1956	.1320	.0693	.0370	.0200	14
15	.4767	.4120	.3563	.3083	.2670	.2314	.1741	.1142	.0573	.0292	.0151	15
16	.4538	.3883	.3326	.2851	.2445	.2099	.1550	.....	.....	.....	.....	16
17	.4319	.3660	.3105	.2636	.2239	.1904	.1379	.....	.....	.....	.....	17
18	.4111	.3450	.2898	.2437	.2050	.1727	.1227	.....	.....	.....	.....	18
19	.3913	.3252	.2706	.2253	.1878	.1566	.1092	.....	.....	.....	.....	19
20	.3724	.3066	.2526	.2083	.1719	.1420	.0972	.....	.....	.....	.....	20
21	.3545	.2890	.2358	.1926	.1574	.1288	.0865	.....	.....	.....	.....	21
22	.3374	.2724	.2201	.1780	.1442	.1169	.0770	.....	.....	.....	.....	22
23	.3211	.2567	.2055	.1646	.1320	.1060	.0685	.....	.....	.....	.....	23
24	.3057	.2420	.1918	.1522	.1209	.0961	.0610	.....	.....	.....	.....	24
25	.2909	.2281	.1791	.1407	.1107	.0872	.0543	.....	.....	.....	.....	25
26	.2769	.2150	.1671	.1301	.1014	.0791	.0483	.....	.....	.....	.....	26
27	.2636	.2027	.1560	.1203	.0928	.0717	.0430	.....	.....	.....	.....	27
28	.2509	.1910	.1457	.1112	.0850	.0651	.0383	.....	.....	.....	.....	28
29	.2388	.1801	.1360	.1028	.0778	.0590	.0341	.....	.....	.....	.....	29
30	.2273	.1697	.1269	.0951	.0713	.0535	.0303	.....	.....	.....	.....	30

TABLE XVIII.—AMOUNT OF $1 IN n YEARS AT THE FOLLOWING RATES OF INTEREST COMPOUNDED SEMI-ANNUALLY

Years	5%	6%	7%	8%	9%	10%	12%	15%	20%	25%	30%	Years
1	1.0506	1.0609	1.0712	1.0816	1.0920	1.1025	1.1236	1.1556	1.21	1.2656	1.3225	1
2	1.1038	1.1255	1.1475	1.1699	1.1925	1.2155	1.2625	1.3335	1.4641	1.6018	1.7490	2
3	1.1597	1.1941	1.2293	1.2653	1.3023	1.3401	1.4185	1.5433	1.7716	2.0273	2.3131	3
4	1.2184	1.2668	1.3168	1.3686	1.4221	1.4775	1.5938	1.7835	2.1436	2.5658	3.0590	4
5	1.2801	1.3439	1.4106	1.4802	1.5530	1.6289	1.7908	2.0610	2.5937	3.2473	4.0456	5
6	1.3449	1.4258	1.5111	1.6010	1.6959	1.7959	2.0122	2.3818	3.1384	4.1099	5.3503	6
7	1.4130	1.5126	1.6187	1.7317	1.8519	1.9799	2.2609	2.7524	3.7975	5.2016	7.0757	7
8	1.4845	1.6047	1.7340	1.8730	2.0224	2.1829	2.5404	3.1808	4.5950	6.5833	9.3576	8
9	1.5597	1.7024	1.8575	2.0258	2.2085	2.4066	2.8543	3.6758	5.5599	8.3319	12.3755	9
10	1.6386	1.8061	1.9898	2.1911	2.4117	2.6533	3.2071	4.2479	6.7275	10.5451	16.3665	10
11	1.7216	1.9161	2.1315	2.3699	2.6337	2.9253	3 6035	4.9089	8.1403	13.3461	21.6447	11
12	1.8087	2.0328	2.2833	2.5633	2.8760	3.2251	4.0489	5.6729	9.8497	16.8912	28.6252	12
13	1.9003	2.1566	2.4460	2.7725	3.1407	3.5557	4.5494	6.5557	11.9182	21.3779	37.8568	13
14	1.9965	2.2879	2.6202	2.9987	3.4297	3.9201	5.1117	7.5759	14.4210	27.0564	50.0656	14
15	2.0976	2.4273	2.8068	3.2434	3.7453	4.3219	5.7435	8.7550	17.4494	34.2433	66.2118	15
16	2.2038	2.5751	3.0067	3.5081	4.0900	4.7649	6.4534	.....	.....	.....	.....	16
17	2.3153	2.7319	3.2209	3.7943	4.4664	5.2533	7.2510	.....	.....	.....	.....	17
18	2.4325	2.8983	3.4503	4.1039	4.8774	5.7918	8.1473	.....	.....	.....	.....	18
19	2.5557	3.0748	3.6960	4.4388	5.3262	6.3855	9.1543	.....	.....	.....	.....	19
20	2.6851	3.2620	3.9593	4.8010	5.8164	7.0400	10.2857	.....	.....	.....	.....	20
21	2.8210	3.4607	4.2413	5.1928	6.3516	7.7616	11.5570	.....	.....	.....	.....	21
22	2.9638	3.6715	4.5433	5.6165	6.9361	8.5572	12.9855	.....	.....	.....	.....	22
23	3.1139	3.8950	4.8670	6.0748	7.5744	9.4343	14.5905	.....	.....	.....	.....	23
24	3.2715	4.1323	5.2136	6.5705	8.2715	10.4013	16.3939	.....	.....	.....	.....	24
25	3.4371	4.3839	5.5849	7.1067	9.0326	11.4674	18.4211	.....	.....	.....	.....	25
26	3.6111	4.6509	5.9827	7.6866	9.8639	12.6428	20.6969	.....	.....	.....	.....	26
27	3.7939	4.9341	6.4088	8.3138	10.7716	13.9387	23.2550	.....	.....	.....	.....	27
28	3.9860	5.2346	6.8653	8.9922	11.7628	15.3674	26.1293	.....	.....	.....	.....	28
29	4.1878	5.5534	7.3543	9.7260	12.8453	16.9426	29.3589	.....	.....	.....	.....	29
30	4.3998	5.8916	7.8781	10.5196	14.0274	18.6792	32.9877	.....	.....	.....	.....	30

TABLE XIX.—PRESENT VALUE OF AN ANNUITY OF $1 FOR n YEARS AT THE FOLLOWING RATES OF INTEREST COMPOUNDED SEMI-ANNUALLY, THE FIRST PAYMENT BEING RECEIVED AT THE END OF 6 MONTHS

Years	5%	6%	7%	8%	9%	10%	12%	15%	20%	25%	30%	Years
1	$ .9756	$ .9709	$ .9662	$ .9615	$ .9569	$ .9524	$ .9434	$ .9302	$ .9091	$ .8889	$ .8696	1
2	1.9042	1.8860	1.8681	1.8505	1.8332	1.8162	1.7830	1.7352	1.6604	1.5912	1.5271	2
3	2.7881	2.7486	2.7101	2.6725	2.6357	2.5997	2.5303	2.4317	2.2813	2.1461	2.0243	3
4	3.6293	3.5617	3.4961	3.4324	3.3705	3.3104	3.1953	3.0345	2.7945	2.5846	2.4002	4
5	4.4300	4.3281	4.2298	4.1350	4.0434	3.9550	3.7872	3.5561	3.2186	2.9310	2.6845	5
6	5.1922	5.0505	4.9147	4.7846	4.6596	4.5397	4.3140	4.0074	3.5691	3.2048	2.8994	6
7	5.9176	5.7315	5.5541	5.3851	5.2239	5.0700	4.7829	4.3980	3.8587	3.4211	3.0619	7
8	6.6081	6.3734	6.1510	5.9404	5.7406	5.5511	5.2001	4.7360	4.0981	3.5919	3.1848	8
9	7.2653	6.9784	6.7082	6.4538	6.2138	5.9874	5.5715	5.0284	4.2960	3.7270	3.2778	9
10	7.8908	7.5487	7.2283	6.9284	6.6471	6.3831	5.9020	5.2815	4.4595	3.8337	3.3480	10
11	8.4862	8.0862	7.7139	7.3672	7.0439	6.7420	6.1962	5.5005	4.5946	3.9179	3.4012	11
12	9.0529	8.5929	8.1672	7.7730	7.4072	7.0676	6.4579	5.6900	4.7063	3.9845	3.4413	12
13	9.5923	9.0705	8.5903	8.1481	7.7400	7.3629	6.6909	5.8540	4.7986	4.0372	3.4717	13
14	10.1057	9.5207	8.9853	8.4949	8.0447	7.6307	6.8983	5.9959	4.8749	4.0787	3.4947	14
15	10.5943	9.9451	9.3541	8.8155	8.3237	7.8737	7.0829	6.1187	4.9379	4.1116	3.5121	15
16	11.0594	10.3450	9.6983	9.1120	8.5792	8.0941	7.2471	.....	.....	.....	.....	16
17	11.5021	10.7221	10.0196	9.3861	8.8131	8.2939	7.3933	.....	.....	.....	.....	17
18	11.9235	10.0775	10.3196	9.6395	9.0274	8.4752	7.5234	.....	.....	.....	.....	18
19	12.3246	11.4124	10.5997	9.8738	9.2236	8.6397	7.6392	.....	.....	.....	.....	19
20	12.7063	11.7282	10.8611	10.0904	9.4033	8.7888	7.7423	.....	.....	.....	.....	20
21	13.0697	12.0258	11.1051	10.2907	9.5678	8.9241	7.8340	.....	.....	.....	.....	21
22	13.4155	12.3064	11.3329	10.4759	9.7185	9.0468	7.9156	.....	.....	.....	.....	22
23	13.7447	12.5708	11.5456	10.6471	9.8564	9.1581	7.9883	.....	.....	.....	.....	23
24	14.0580	12.8200	11.7441	10.8054	9.9828	9.2590	8.0529	.....	.....	.....	.....	24
25	14.3562	13.0550	11.9294	10.9517	10.0984	9.3506	8.1105	.....	.....	.....	.....	25
26	14.6400	13.2765	12.1024	11.0870	10.2044	9.4336	8.1617	.....	.....	.....	.....	26
27	14.9102	13.4852	12.2639	11.2121	10.3014	9.5090	8.2073	.....	.....	.....	.....	27
28	15.1674	13.6820	12.4147	11.3278	10.3902	9.5773	8.2478	.....	.....	.....	.....	28
29	15.4121	13.8675	12.5554	11.4347	10.4716	9.6393	8.2839	.....	.....	.....	.....	29
30	15.6451	14.0423	12.6868	11.5336	10.5461	9.6955	8.3160	.....	.....	.....	.....	30

TABLE XX.—PRESENT VALUE OF AN ANNUITY OF $1 FOR n YEARS AT THE FOLLOWING RATES OF INTEREST COMPOUNDED SEMI-ANNUALLY, THE FIRST PAYMENT BEING RECEIVED AT THE END OF THE FIRST YEAR

Years	5%	6%	7%	8%	9%	10%	12%	15%	20%	25%	30%	Years
1	$ .9518	$ .9426	$ .9335	$ .9246	$ .9157	$ .9070	$ .8900	$ .8653	$ .8264	$ .7901	$ .7561	1
2	1.8578	1.8311	1.8049	1.7794	1.7543	1.7297	1.6821	1.6141	1.5095	1.4144	1.3279	2
3	2.7201	2.6686	2.6184	2.5697	2.5222	2.4759	2.3871	2.2621	2.0739	1.9077	1.7602	3
4	3.5408	3.4580	3.3779	3.3004	3.2254	3.1528	3.0145	2.8228	2.5404	2.2974	2.0871	4
5	4.3220	4.2021	4.0868	3.9759	3.8693	3.7667	3.5729	3.3080	2.9260	2.6054	2.3343	5
6	5.0656	4.9035	4.7486	4.6005	4.4590	4.3235	4.0698	3.7278	3.2446	2.8487	2.5212	6
7	5.7733	5.5646	5.3663	5.1780	4.9990	4.8286	4.5121	4.0911	3.5079	3.0409	2.6625	7
8	6.4469	6.1877	5.9430	5.7119	5.4934	5.2867	4.9058	4.4055	3.7256	3.1928	2.7694	8
9	7.0881	6.7751	6.4814	6.2055	5.9462	5.7022	5.2561	4.6776	3.9054	3.3129	2.8502	9
10	7.6983	7.3288	6.9840	6.6619	6.3609	6.0791	5.5679	4.9130	4.0541	3.4077	2.9113	10
11	8.2792	7.8507	7.4531	7.0839	6.7406	6.4210	5.8454	5.1167	4.1769	3.4826	2.9575	11
12	8.8321	8.3426	7.8911	7.4740	7.0883	6.7310	6.0924	5.2930	4.2784	3.5418	2.9924	12
13	9.3583	8.8063	8.2999	7.8347	7.4067	7.0123	6.3122	5.4455	4.3624	3.5886	3.0189	13
14	9.8592	9.2434	8.6816	8.1682	7.6982	7.2674	6.5078	5.5775	4.4317	3.6256	3.0388	14
15	10.3359	9.6554	9.0379	8.4765	7.9652	7.4988	6.6819	5.6917	4.5890	3.6548	3.0539	15
16	10.7897	10.0437	9.3705	8.7616	8.2097	7.7086	6.8369	.....	.....	.....	.....	16
17	11.2216	10.4098	9.6809	9.0251	8.4336	7.8990	6.9748	.....	.....	.....	.....	17
18	11.6327	10.7548	9.9708	9.2688	8.6386	8.0716	7.0976	.....	.....	.....	.....	18
19	12.0240	11.0800	10.2413	9.4941	8.8264	8.2283	7.2068	.....	.....	.....	.....	19
20	12.3964	11.3866	10.4939	9.7024	8.9983	8.3703	7.3040	.....	.....	.....	.....	20
21	12.7509	11.6756	10.7297	9.8949	9.1558	8.4991	7.3905	.....	.....	.....	.....	21
22	13.0883	11.9479	10.9498	10.0730	9.2999	8.6160	7.4675	.....	.....	.....	.....	22
23	13.4094	12.2047	11.1552	10.2376	9.4320	8.7220	7.5361	.....	.....	.....	.....	23
24	13.7151	12.4467	11.3471	10.3898	9.5529	8.8181	7.5971	.....	.....	.....	.....	24
25	14.0060	12.6748	11.5261	10.5305	9.6636	8.9053	7.6514	.....	.....	.....	.....	25
26	14.2829	12.8898	11.6932	10.6606	9.7650	8.9844	7.6997	.....	.....	.....	.....	26
27	14.5465	13.0925	11.8493	10.7809	9.8578	9.0562	7.7427	.....	.....	.....	.....	27
28	14.7974	13.2835	11.9949	10.8921	9.9428	9.1212	7.7810	.....	.....	.....	.....	28
29	15.0362	13.4636	12.1309	10.9949	10.0206	9.1803	7.8150	.....	.....	.....	.....	29
30	15.2635	13.6333	12.2578	11.0900	10.0919	9.2338	7.8453	.....	.....	.....	.....	30

TABLE XXI.—VALUE OF A PERPETUAL ANNUITY OF $1 AT THE FOLLOWING RATES OF INTEREST COMPOUNDED ANNUALLY, THE FIRST PAYMENT BEING RECEIVED AT THE END OF THE FIRST YEAR

INTEREST RATE, PER CENT	VALUE OF ANNUITY
5	$20.00
6	16.67
7	14.29
8	12.50
9	11.11
10	10.00
12	8.33
15	6.67
20	5.00
25	4.00
30	3.33

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